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FOR: Any person who uses the Federal Register and Code of Federal Regulations.

WHO: Sponsored by the Office of the Federal Register.

WHAT: Free public briefings (approximately 3 hours) to present:

1. The regulatory process, with a focus on the Federal Register system and the public's role in the development of regulations.
2. The relationship between the Federal Register and Code of Federal Regulations.
3. The important elements of typical Federal Register documents.
4. An introduction to the finding aids of the FR/CFR system.

WHY: To provide the public with access to information necessary to research Federal agency regulations which directly affect them. There will be no discussion of specific agency regulations.

WHEN: Tuesday, November 10, 2009
9 a.m.–12:30 p.m.

WHERE: Office of the Federal Register
Conference Room, Suite 700
800 North Capitol Street, NW.
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CFR PARTS AFFECTED IN THIS ISSUE

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

Rules and Regulations

Federal Register

Vol. 74, No. 209

Friday, October 30, 2009

SMALL BUSINESS ADMINISTRATION

13 CFR Part 120

RIN 3245–AF90

The American Recovery and Reinvestment Act of 2009: Secondary Market First Lien Position 504 Loan Pool Guarantee

AGENCY: U.S. Small Business Administration.

ACTION: Interim final rule with request for comments.

SUMMARY: This interim final rule implements Section 503 of the American Recovery and Reinvestment Act of 2009 (Recovery Act), which establishes a secondary market for the first mortgage loan that is a component of a financing made under the 504 program. The Recovery Act authorizes SBA to establish a program to provide a guarantee for pools comprised of portions of these first mortgage loans that will back certificates to be sold to investors.

DATES: *Effective Date:* This rule is effective October 30, 2009.

Comment Date: Comments must be received on or before January 28, 2010.

Applicability Date: Subpart J of Part 120 is applicable to all eligible First Lien Position 504 Loans financing a Project in conjunction with a 504 loan by a CDC funded by a debenture that was sold on or after February 17, 2009.

ADDRESSES: You may submit comments, identified by RIN: 3245–AF90, by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Mail:* James W. Hammersley, Deputy Assistant Administrator, Office of Policy and Strategic Planning, Small Business Administration, 409 Third Street, SW., Washington, DC 20416.
- *Hand Delivery/Courier:* James W. Hammersley, Deputy Assistant Administrator, Office of Policy and Strategic Planning, 409 Third Street, SW., Washington, DC 20416.

SBA will post all comments on *www.regulations.gov.* If you wish to submit confidential business information (CBI) as defined in the User Notice at www.regulations.gov, please submit the information to James W. Hammersley, Deputy Assistant Administrator, Office of Policy and Strategic Planning, 409 Third Street, SW., Washington, DC 20416, or send an e-mail to *james.hammersley@sba.gov.* Highlight the information that you consider to be CBI and explain why you believe SBA should hold this information as confidential. SBA will review the information and make the final determination whether it will publish the information.

FOR FURTHER INFORMATION CONTACT: James W. Hammersley, Deputy Assistant Administrator, Office of Policy and Strategic Planning, at *james.hammersley@sba.gov.*

SUPPLEMENTARY INFORMATION:

I. Background Information

The American Recovery and Reinvestment Act of 2009 (Recovery Act), Public Law 111–5, was enacted on February 17, 2009, to, among other things, promote economic recovery by preserving and creating jobs, and assisting those most impacted by the severe economic conditions facing the nation. The U.S. Small Business Administration is one of several agencies that will play a role in achieving these goals.

As authorized by the Recovery Act, this rule will establish a temporary secondary market guarantee program for pools comprised of first mortgage loans made under SBA's 504 program. The 504 program provides long-term, fixed rate financing to small businesses for expansion or modernization, primarily of real estate (including land and new building construction, existing building purchases or renovation, and machinery and equipment). Financing is delivered through Certified Development Companies (CDCs), which are private primarily nonprofit entities established pursuant to the 504 program to contribute to the economic development of their communities. In a typical 504 program project, a lender (First Lien Position 504 Lender) provides a loan for 50 percent or more of the Project costs (the First Lien Position 504 Loan), the CDC provides a loan for up to 40% of the Project costs (the 504 loan) funded through the sale of a debenture that is fully guaranteed by SBA, and the small business receiving the financing contributes at least 10 percent of the Project costs. The CDC obtains the funds to make the 504 loan by issuing a debenture that is guaranteed by SBA (CDC Debenture). The small business must meet eligibility requirements for SBA financial assistance, and a project generally must create or retain at least one job for every $65,000 guaranteed by SBA. First Lien Position 504 Lenders, small business borrowers, and CDCs in the 504 program are required to pay various fees to offset the costs of the program. Regulations implementing the 504 program are in Subpart H of Part 120 of SBA's regulations. (13 CFR Part 120, Subpart H).

Over the years, the development of secondary markets for 504 loans facilitated the capacity of CDCs to originate such loans and small businesses to apply for them. By selling loans to investors via the secondary markets, among other benefits, lenders can receive additional funds, or liquidity, which can enable them to make more loans. Sellers, broker-dealers, and other secondary market participants make profits from the premiums that investors pay for the securities, through various fees, and through servicing the loans over time. There is a secondary market for CDC Debentures and another secondary market for the First Lien Position 504 Loans. Due to the disruption in the credit markets, there has been a significant decline in secondary market activity relating to First Lien Position 504 Loans. Section 503 of the Recovery Act provides authority to SBA to assist the secondary market for the First Lien Position 504 Loans by allowing the SBA Administrator to establish a secondary market guarantee for pools of First Lien Position 504 Loans to sell to third-party investors. The authority terminates on February 16, 2011, which is two years after enactment. First Lien Position 504 Loans are eligible to be part of a pooling if, among other things, the debenture funding the associated loan by a CDC was sold on or after February 17, 2009.

II. Section-by-Section Analysis of New Subpart J of Part 120

The defined terms in subpart J include:

504 financing. The loans made to a small business to fund a Project under the SBA's development company loan program authorized by Title V of the Small Business Investment Act of 1958.

Affiliate. A person or entity SBA determines to be an affiliate of a Program Participant pursuant to the application of the principles and guidelines set forth in section 121.103 of this Title.

Certified Development Company or CDC. An entity as defined in section 120.10 of this Part.

Central Servicing Agent or CSA. The entity serving as SBA's central servicing agent for the Program.

Current. That no scheduled payment owed by an Obligor pursuant to a Pool Note is over 29 days past due.

First Lien Position 504 Loan. The financing provided by the First Lien Position 504 lender that is part of the 504 project financing.

First Lien Position 504 Loan Pool Guarantee Agreement. The agreement, in the form approved by SBA, wherein entities agree to participate in the forming of a Pool under the Program, available at *http://www.sba.gov/aboutsba/sbaprograms/elending/index.html.*

Guide. The SBA First Lien Position 504 Loan Pooling Program Guide published by SBA which provides information applicable to the Program including, among other things, requirements relating to the formation of a Pool, available at *http://www.sba.gov/aboutsba/sbaprograms/elending/index.html.*

Liquidation Proceeds. Cash, including insurance proceeds, proceeds of any foreclosed-on property disposition, revenues received with respect to the conservation and disposition of a foreclosed-on property or repossessed collateral, including any real property securing the Pool Loan, consisting of a commercial property or residential property and any improvements thereon, and any other amounts received in connection with the liquidation of the Pool Loan, whether through Seller's sale, foreclosure sale, any offset or workout, or otherwise.

Loan Interest. The right to receive the owned portion of the principal balance of the Pool Loan together with interest thereon at a per annum rate in effect from time to time in accordance with the First Lien Position 504 Loan Pool Guarantee Agreement.

Maturity. The maturity of the Loan Interest in the Pool that has the longest remaining term of any Loan Interest in the Pool. The maturity will change from time to time due to prepayment or default on Loan Interests in the Pool.

Obligor. The obligor(s) under a Pool Note.

Ongoing Guarantee Fee. An annual fee collected monthly and based on the percentage of the Pool Loan that is in the pool, pursuant to section 503(C)(3)(B)(ii) of the Recovery Act, to result in a cost of the loan guarantee of zero as determined under the Federal Credit Reform Act of 1990, as amended. The funds generated by the fee serve as a reserve to pay for program losses. The fee will be published in a Notice by SBA prior to the commencement of the program.

Pool. The aggregate of Loan Interests formed into a single pool by the Pool Originator in accordance with the Program. The Pool is comprised of an unguaranteed portion and an SBA-guaranteed portion. The unguaranteed portion of the Pool backs the Pool Originator Receipt, and cannot be sold to Pool Investors. The SBA-guaranteed portion of the Pool backs the Pool Certificates which may be sold to Pool Investors. The Seller's Loan Interest is not included in the Pool.

Pool Assembler. An entity that meets the qualifications set forth in section 120.630 of this Part and has been approved as such by SBA.

Pool Certificate. The document representing a beneficial fractional interest in the SBA-guaranteed portion of a Pool.

Pooled. When one or more Loan Interests in a Pool Loan has been put into a Pool.

Pooling. The transfer of one or more Loan Interests in a Pool Loan into a Pool.

Pool Investor. An entity which holds a Pool Certificate in accordance with Program Rules and Regulations.

Pool Loan. A loan that meets the Program eligibility requirements set forth in section 120.1704 of this subpart J and has been pooled.

Pool Loan Receivables. Pool Loan payments, prepayments, or collections made in connection with the Pool Loan by the Obligor pursuant to Pool Note or any other Pool Loan documents or agreements, or by another person or entity made on behalf of any such Pool Loan obligor, and Liquidation Proceeds.

Pool Note. The document evidencing a Pool Loan.

Pool Originator. An entity approved by SBA to pool Loan Interests under the Program.

Pool Originator Receipt. The document evidencing the Pool Originator's retained ownership in a Pool it has formed under the Program.

Premier Certified Lenders Program. The program defined in section 120.845 of this Part.

Program. The program authorized by section 503 of the American Recovery and Reinvestment Act of 2009.

Program Participant. An entity that executes the First Lien Position 504 Loan Pool Guarantee Agreement as Seller, Pool Originator, or Pool Investor, and any successors or assignees thereof.

Program Participant Associate. (i) An officer, director, key employee, or holder of 20 percent or more of the value of a Program Participant's stock or debt instruments, or (ii) any individual in which one or more individuals referred to in clause (i) of this definition, or a spouse, or child, or sibling, or the spouse of any such individual, owns or controls at least 20 percent.

Program Preference. Any arrangement giving the Seller, or a Program Associate or Affiliate of Seller, a preference or benefit of proportion greater than its Loan Interest as compared to Pool Originator, Pool Investor, or SBA relating to the making, servicing, or liquidation of the Pool Loan with respect to such things as repayment, collateral, guarantees, control, maintenance of a compensating balance, purchase of a certificate of deposit or acceptance of a separate or companion loan, without SBA's consent. Seller's agreement to grant a Pool Loan's Obligor a deferment in return for receiving more collateral on a different loan owned by Seller is an example of a preference.

Program Rules and Regulations. This subpart J, as may be amended from time to time by SBA, the Program Regulations, available at *http://www.sba.gov/aboutsba/sbaprograms/elending/index.html,* the First Lien Position 504 Loan Pool Guarantee Agreement, available at *http://www.sba.gov/aboutsba/sbaprograms/elending/index.html,* any other Program agreements signed by a Program Participant, if applicable, the Guide, available at *http://www.sba.gov/aboutsba/sbaprograms/elending/index.html,* the Recovery Act available at Recovery.gov, and the provisions of subpart H governing Third Party Loans and Third Party Lenders available at *http://www.sba.gov/aboutsba/sbaprograms/elending/index.html.*

Project. A project as defined by section 120.802 of this Part.

SBA. The United States Small Business Administration, an agency of the United States Government.

Seller. An entity that has sold a Pool Loan to a Pool Originator to be Pooled.

Seller's Pool Loan. The Pool Loan sold to a Pool Originator pursuant to the First Lien Position 504 Loan Pool Guarantee Agreement.

Seller Receipt. The document that evidences a Seller's retained Loan Interest in a Pool Loan.

Servicing Retention Amount. The amount of a Pool Loan interest payment retained by Seller for servicing the Pool Loan that is payable and calculated pursuant to the First Lien Position 504 Loan Pool Guarantee Agreement. This approach is customary for loans sold in the secondary market.

Weighted Average Interest Rate. The dollar-weighted average interest rate of a Pool Certificate calculated by multiplying the interest rate of each Loan Interest in the Pool by the ratio of that Loan Interest's current outstanding principal in the SBA-guaranteed portion of the Pool (that is, the portion of the Pool Loan backing the Pool Certificates) to the current aggregate or outstanding principal of each Loan Interest in the SBA-guaranteed portion of the Pool, and adding the sum of the resulting products. The Pool Certificate interest rate will fluctuate over the life of the Pool as defaults, prepayments and normal repayments applicable to a Pooled Loan Interest occurs.

Weighted Average Maturity. The weighted average maturity of a Pool Certificate is a dollar weighted average maturity that is calculated by multiplying the remaining term, in months, of each Loan Interest in a Pool by the ratio of that Loan Interest's current outstanding pooled principal to the current aggregate outstanding pooled principal of all Loan Interests in the Pool, and adding the sum of the resulting products. The weighted average maturity of a Pool Certificate will fluctuate over the life of the Pool as Loan Interest defaults, prepayments and normal Loan Interest repayments occur.

An important term defined in subpart J is ''Loan Interest''. A Loan Interest is the right to receive the owned portion of the principal balance of a loan together with interest thereon at a per annum rate in effect from time to time in accordance with the applicable program agreement. Under the program, the pooling process results in a First Lien Position 504 Loan being split into three separate parts, or Loan Interests. One Loan Interest will be held by a Seller that will be equal to 15% or more of the Pool Loan and will be evidenced by a document issued by the Central Servicing Agent (CSA) called a Seller Receipt. The Seller's Loan Interest will not be part of the Pool, and is not guaranteed under this program. A second Loan Interest will be held by a Pool Originator in an unguaranteed portion of a Pool that will be equal to 5% or more of the aggregate of each Loan Interest in the Pool, and will be evidenced by a Pool Originator Receipt. A third Loan Interest will be put into the pool and be fully guaranteed by SBA, and will back Pool Certificates sold to Pool Investors. The part of the pool of Loan Interests backing a Pool Originator Receipt is referred to as the unguaranteed portion of the Pool. The part of the pool of Loan Interests backing a Pool Certificate is referred to as the SBA-guaranteed portion of the Pool.

Under the Program, in connection with the forming of a particular pool, it is possible for the Seller and Pool Originator to be the same entity; however, a Seller or a Pool Originator cannot be a Pool Investor for that pool. In such a case, the entity pooling a Pool Loan it made or acquired prior to the pooling would execute the First Lien Position 504 Loan Pool Guarantee Agreement as Seller, the party responsible for servicing the Pool Loan and retaining at least a 15% Loan Interest in the Pool Loan, and as Pool Originator, the party placing 85% or less of the Loan Interest in the Pool Loan into the Pool (with at least 5% of the Loan Interest in the Pool Loan going into the unguaranteed portion of the Pool). In such a scenario, a single entity (the Pool Originator) would hold 20% or more of the Loan Interest in a Pool Loan that is unguaranteed, cannot be sold to Pool Investors, and must be serviced pursuant to the Program Rules and Regulations.

Section 120.1701 describes the purpose of this temporary Program. The purpose of the Program is to provide a federal guarantee for Pools of First Lien Position 504 Loans to facilitate the sale of such loans and increase the liquidity of the lenders holding the loans so that the lenders can use the sale proceeds to fund more such loans.

Section 120.1702 discusses the SBA fee for guaranteeing a portion of the pool, which is called the Ongoing Guarantee Fee. The Ongoing Guarantee Fee is collected from program participants and is used to pay program losses.

Section 120.1703 establishes the qualifications applicable to becoming a Pool Originator under the Program. An entity applying to become a Pool Originator must send an application to SBA certifying that it is an approved Pool Assembler pursuant to subpart F of this Title or it: (1) Is regulated by the appropriate agency as defined in section 3(a)(34)(G) of the Securities Exchange Act of 1934 (15 U.S.C. 78c(a)(34)(G)); (2) meets all financial and other applicable requirements of its regulatory authority and the Government Securities Act of 1986, as amended (Pub. L. 99–571, 100 Stat. 3208); (3) has the financial capability to originate acceptable pools consisting of eligible Pool Loans in sufficient quantity to support the issuance of Pool Certificates; and (4) is in good standing with the SBA (as the SBA determines), Office of the Comptroller of the Currency (OCC) if it is a national bank, the Federal Deposit Insurance Corporation if it is a bank not regulated by the OCC, the Financial Institutions Regulatory Authority, if it is a member, the National Credit Union Administration if it is a credit union, and (5) for any Pool Originator that is an SBA Lender, that the SBA Lender has satisfactory SBA performance, as determined by SBA in its sole discretion.

Section 120.1704 establishes which loans are eligible to be part of a pooling under the Program. It states, among other things, that eligible Pool Loans must: (1) Be Current and have been Current for the six-month period immediately prior to the date the Pool is formed or for the life of the Pool Loan, whichever time period is shorter; (2) have been closed and serviced in accordance with Program Rules and Regulations; (3) be part of a completed 504 financing, funded by a CDC debenture, which means that the Pool Loan must be fully disbursed, and that the debenture funding the CDC loan must have been sold on or after February 17, 2009; and (4) not be (i) to a business deriving more than one-third of its gross annual revenue from legal gambling activities; (ii) to a casino, gambling establishment, or casino hotel; (iii) for financing the acquisition, construction or renovation of an aquarium, zoo, golf course, or swimming pool; or (iv) to a business covered by a six-digit North American Industry Classification System (NAICS) code for casinos—713210 (''Casinos (Except Casino Hotels)''); casino hotels—721120 (''Casino Hotels''); other gambling institutions—713290 (''Other Gambling Industries''); golf courses—713910 (''Golf Courses and Country Clubs''); or aquariums and zoos—712130 (''Zoos and Botanical Gardens''). The restrictions on the business activities identified in (i) through (iv) above arise from the fact that the guaranty on the pool is established in the Recovery Act. The Recovery Act provides that these types of businesses may not receive any assistance provided directly or indirectly by the Act.

A Pool Originator must identify and submit to SBA for review Pool Loans to businesses with NAICS code 713940 covering Fitness and Recreational Sports Centers, as this category includes both swimming pools, which are not eligible for assistance under the Recovery Act, and other types of fitness and recreational centers which may be eligible for Recovery Act assistance. Section 1604 of the Recovery Act states that none of the funds appropriated or otherwise made available in the Act may be used by any State or local government, or any private entity, for any casino or other gambling establishment, aquarium, zoo, golf course or swimming pool. SBA may not guarantee a pool that contains a Pool Loan made to a business primarily engaged in any such activities or to a business that used the loan funds to acquire, construct, renovate or for another purpose that included the restricted uses.

Section 120.1705 establishes requirements relating to Pool formation. It states that only an entity approved by SBA to be a Pool Originator under the Program and that continues to qualify to be a Pool Originator pursuant to subpart J may initiate the formation of a Pool. The Pool's characteristics must meet the parameters set forth in the Guide created by SBA for this Program, which may be adjusted based on market conditions and program experience. A revised version of the Guide will be published in the **Federal Register** to reflect any such changes.

Section 120.1706 establishes a Pool Originator's required retained interest in each Pool it forms under the program. It states that the Pool Originator must retain an ownership interest in any such Pool equal to at least 5% of the aggregate of the total outstanding principal balance of each Pool Loan with a Loan Interest in the pool as calculated at the time of pool formation. At Pool formation, the CSA will issue the Pool Originator a Pool Originator Receipt evidencing the Pool Originator's retained interest in the Pool. The Pool Originator may not sell, pledge, participate, hypothecate, or otherwise transfer its Pool Originator Receipt or any interest therein for the life of the Pool.

Section 120.1707 establishes a Seller's required retained interest in the Pool Loan it sells to the Pool Originator at the time of Pool formation under the program, and states that the Seller must retain a 15% or greater Loan Interest in such loan. At pool formation, the CSA will issue the Seller a Seller Receipt evidencing the Seller's retained ownership in the Pool Loan. With SBA's written permission, the Seller may sell the Seller Receipt and Servicing Retention Amount in whole, but not in part, to a single entity at one time. The Seller may not sell less than 100% of the Seller Receipt and Servicing Retention Amount and may not sell a participation interest in any portion of the loan. In addition, in order to complete the sale, Seller must have the purchaser of its rights to the Pool Loan execute the First Lien Position 504 Loan Pool Guarantee Agreement as Seller and deliver the executed original to the CSA.

Section 120.1708 establishes the characteristics of Pool Certificates. It states, among other things, that: (1) A Pool Certificate represents a fractional beneficial interest in a Pool; (2) it is self-liquidating by payments on Loan Interests in the Pool; (3) the CSA prepares the Pool Certificate; (4) SBA must approve the form and terms of the Pool Certificate; and (5) it must be registered with the CSA.

Section 120.1709 discusses how a Pool Certificate can be transferred. It establishes, that, in order for the transfer of a Pool Certificate to be effective, the CSA must reflect the transfer on its records. It also establishes the content of the applicable transmittal letter relating to the transfer and that the transfer costs due to the CSA must be paid prior to transfer. It also states that such transfers must comply with Article 8 of the Uniform Commercial Code (UCC) of the State of New York. (Because each Pool Certificate will be an immobilized certificate held in New York and ownership transfers will occur as outlined in Article 8 of the UCC, Article 8 of the UCC of the State of New York applies.)

Section 120.1710 establishes the CSA responsibilities related to the central servicing of the Program. It states that the CSA must: (1) Issue a Seller Receipt to the Seller, a Pool Originator Receipt to the Pool Originator, and a Pool Certificate to each Pool Investor; (2) forward all Loan Receivables it receives to pay the Servicing Retention Amount, Ongoing Guarantee Fee, Seller Receipt, Pool Originator Receipt, Pool Certificates, and any other applicable payment in accordance with Program Rules and Regulations; (3) maintain a registry of Pool Investors and other information as SBA requires; (4) register all Pool Certificates; and (5) provide SBA with a list, by Pool, of each Loan Interest with an underlying note that is 60 days or more in arrears on a monthly basis.

Section 120.1711 establishes the conditions pursuant to which a Participant's participation privileges may be suspended or terminated by SBA and a Participant's right to appeal such suspension or termination. It states that SBA may, by following the procedures set forth in the section, suspend or terminate the privilege of a Participant, and/or any Associate or Affiliate of the Participant, to sell, purchase, broker, or deal in loans, Loan Interests, or Pool Certificates under the program if any such Participant or its Associate or Affiliate has:

(1) Failed to comply materially with any requirement imposed by Program Rules and Requirements, or (2) making a material false statement or failure to disclose a material fact to SBA. Section 120.1711 also establishes additional grounds for the suspension or termination of a Pool Originator which are related to the Pool Originator's fitness to form Pools.

Section 120.1712 establishes that Seller's responsibilities with respect to Seller's Pool Loan shall remain in effect for the life of such loan unless SBA provides written notice to the contrary.

Section 120.1713 establishes the standards applicable to Seller's origination of Seller's Pool Loan. It states that the Seller is responsible for having made and closed Seller's Pool Loan in a commercially reasonable manner, consistent with prudent lending standards, and in accordance with any applicable Program Rules and Regulations.

Section 120.1714 establishes the standards and requirements applicable to Seller's servicing of Seller's Pool Loan. It states that the Seller must service Seller's Pool Loan, subject to section 120.1718 of this subpart J, in a commercially reasonable manner, consistent with prudent lending standards, and in accordance with applicable Program Rules and Regulations.

Section 120.1715 establishes the standards and requirements applicable to Seller's liquidation of Seller's Pool Loan. It states that, subject to 120.1718 of the subpart, the Seller must liquidate and conduct debt collection litigation for Seller's Pool Loan in a prompt, cost-effective and commercially reasonable manner, consistent with prudent lending standards, in accordance with applicable Program Rules and Regulations, and with SBA approval of either a liquidation or litigation plan or any amendment of such a plan, if applicable.

Section 120.1716 establishes the servicing actions by Seller which need SBA's prior approval. It states that Seller shall not, without prior written consent of SBA, take the following actions with respect to Seller's Pool Loan: (1) Make or consent to any substantial alteration in the terms (''substantial'' includes, but is not limited to, any changes to the principal amount or interest rate); (2) accelerate the maturity; (3) sue; or (4) waive or release any claim. Guidance on other servicing actions, some of which may need prior SBA approval, is provided in the Guide.

Section 120.1717 establishes when a Seller may defer payments on Seller's Pool Loan without SBA's prior approval. It states that, without the prior written consent of SBA, Seller, at the request of Obligor, may grant one deferment of Obligor's scheduled payments for a continuous period not to exceed three months of past or future installments. Seller shall immediately notify CSA of any payment deferment and that notification shall include (1) the SBA Pool Loan Number, (ii) the Obligor's name, (iii) the terms of such deferment, (iv) the date Obligor is to resume payment and (v) reconfirmation of the basis of interest calculation (e.g. 30/360 or Actual Days/365).

Section 120.1718 establishes SBA's right to assume Seller's responsibilities with respect to Seller's Pool Loan. It states that SBA may, in its sole discretion, undertake the servicing, liquidation and/or litigation of Seller's Pool Loan at any time and, in such event, Seller must take any steps necessary to facilitate the assumption by SBA of such responsibilities, which can be transferred by SBA at its discretion to a contractor, agent or other entity.

Section 120.1719 establishes when SBA is entitled to recover from Seller monies paid by SBA under the Program. It establishes that SBA is entitled to recover from Seller any monies paid on SBA's guarantee of a Pool Certificate backed in part by Seller's Pool Loan, plus interest, if SBA in its sole discretion determines that any of the following events has occurred:

(1) Seller's improper action or inaction has put SBA at risk;

(2) Seller has failed to disclose a material fact to SBA regarding a Seller's Pool Loan in a timely manner;

(3) Seller has misrepresented a material fact to SBA regarding Seller's Pool Loan;

(4) Seller has failed to comply materially with section 120.1720 of this subpart;

(5) SBA has received a written request from Seller to terminate the SBA's guarantee on the Loan Interest in Seller's Pool Loan;

(6) Seller has failed to comply materially with Program Rules and Regulations; or

(7) Seller has failed to make, close, service or liquidate Seller's Pool Loan in a prudent manner.

Section 120.1720 establishes SBA's right to review Seller's Pool Loan documents. It establishes that, in the event that SBA purchases a Loan Interest in Seller's Pool Loan, Seller must provide to SBA copies of the Pool Loan collateral documents, Pool Loan underwriting documents, and any other documents SBA may require in writing within 30 calendar days of a written request from SBA (which SBA will review in connection with its efforts to determine if Seller is obligated to reimburse SBA pursuant to this subpart). A Seller's failure to provide the requested documentation may constitute a material failure to comply with the Program Rules and Regulations and may lead to an action for recovery under 120.1719. SBA will also evaluate a Seller's continued participation in the Program and may restrict further sales under the Program until SBA determines that the Seller has provided sufficient documentation.

Section 120.1721 establishes a Seller's responsibility to facilitate an SBA investigation into whether Seller is responsible for reimbursing SBA for a loss incurred by it under the program due to Seller's improper actions. It establishes that SBA may undertake such investigation as it deems necessary to determine whether it is entitled to seek recovery from the Seller and that the Seller agrees to take whatever actions are necessary to facilitate such investigation.

Section 120.1722 establishes SBA's offset rights with respect to Seller. It states SBA shall have the right to offset any amount owed by Lender to SBA, including, without limitation, an offset against CSA's obligation to pay Lender pursuant to any Section 504 First Mortgage Loan Pool Guarantee Agreement.

Section 120.1723 establishes when Seller must forward Pool Loan Receivables to CSA. It states that any loan receivables received by Seller in connection with obligations under Seller's Pool Loan must be forwarded by Seller to CSA within two business days of receipt of collected funds. Pool Loan Receivables include Liquidation Proceeds.

Section 120.1724 discusses how ordinary servicing and liquidation expenses incurred by Seller are recoverable from SBA and the applicable Pool Originator and Pool Investors. It establishes that all ordinary and reasonable expenses of servicing, and liquidating Seller's Pool Loan shall be paid by, or be recoverable from, Obligor, and that all such ordinary and reasonable expenses incurred by Seller or SBA which are not recoverable from Obligor shall be shared ratably by Seller, SBA, and the Pool Originator pursuant to the applicable percentages set forth in the First Lien Position 504 Loan Pool Guarantee Agreement.

Section 120.1725 states that a Seller and the Pool Originator must not establish a Program Preference, which is defined in 13 CFR 120.10.

Section 120.1726 discusses the Pool Certificates a Seller must not purchase. It establishes that neither a Seller, nor any of its Program Associates or Affiliates, may purchase a Pool Certificate that is backed by a Loan Interest in a Pool Loan that the Seller, or any of its Program Associates or Affiliates, originated or owned, and, in the event such purchase occurs, SBA's guarantee shall not be in effect with respect to any such Pool Certificate.

III. Justification for Publication as Interim Final Rule

In general, before issuing a final rule, SBA publishes the rule for public comment in accordance with the Administrative Procedure Act (APA), 5 U.S.C. 553. The APA provides an exception from the general rule where the agency finds good cause to omit public participation. 5 U.S.C. 553(c)(3)(B). The good cause requirement is satisfied when prior public participation can be shown to be impracticable, unnecessary, or contrary to the public interest. Under such circumstances, an agency may publish an interim final rule without soliciting public comment.

In enacting the good cause exception to standard rulemaking procedures, Congress recognized that emergency situations arise where an agency must issue a rule without public participation. The current turmoil in the financial markets is having a negative impact on the availability of financing for small businesses. SBA finds that good cause exits to publish this rule as an interim final rule in light of the urgent need to help small businesses sustain and survive during this economic downturn. Advance solicitation of comments for this rulemaking would be impracticable, contrary to the public interest, and would harm those small businesses that need immediate access to capital.

In addition, the Recovery Act mandates that the SBA issue emergency regulations to implement Section 503 and establish the Secondary Market Guaranty Authority. The Recovery Act also specifically exempts any such regulations from the notice and comment requirement of the APA.

Although this rule is being published as an interim final rule, comments are solicited from interested members of the public. These comments must be submitted on or before 90 days from the date of publication. The SBA will consider these comments and the need for making any amendments as a result of these comments.

IV. Justification for Immediate Effective Date

The APA requires that ''publication or service of a substantive rule shall be made not less than 30 days before its effective date, except * * * as otherwise provided by the agency for good cause found and published with the rule.'' 5 U.S.C. 553(d)(3).

The purpose of this provision is to provide interested and affected members of the public sufficient time to adjust their behavior before the rule takes effect. In light of the current economic downturn and the sharp reduction in commercial lending, it is essential to accelerate the availability of additional 504 financing for small businesses by implementing this rule immediately. In addition, the program has a limited life, so it is important to make the program effective in a timely manner.

SBA finds that that there is good cause for making this rule effective immediately instead of observing the 30-day period between publication and effective date. Delaying implementation of the rule would have a serious adverse impact on the nation's small businesses.

Compliance With Executive Orders 12866, 12988, 13175 and 13132, the Paperwork Reduction Act (44 U.S.C., Ch. 35), and the Regulatory Flexibility Act (5 U.S.C. 601–612) Executive Order 12866

The Office of Management and Budget (OMB) has determined that this rule constitutes a significant regulatory action for purposes of Executive Order 12866.

Executive Order 12988

This action meets applicable standards set forth in sections 3(a) and 3(b)(2) of Executive Order 12988, Civil Justice Reform, to minimize litigation, eliminate ambiguity, and reduce burden. The action does not have preemptive effect, and has retroactive effect only to the extent that interests in loans made prior to the effective date of this rulemaking may be eligible to be sold and pooled in accordance with this rule.

Executive Order 13132

This rule does not have federalism implications as defined in Executive Order 13132. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in the Executive Order. As such it does not warrant the preparation of a Federalism Assessment.

Paperwork Reduction Act

The SBA has determined that this rule imposes new reporting and recordkeeping requirements under the Paperwork Reduction Act, 44 U.S.C. Chapter 35. Because the Recovery Act requires SBA to issue emergency regulations, the agency has submitted a request to the Office of Management and Budget (OMB) for review and approval of the resulting collection of information under the OMB emergency processing procedures regulation, 5 CFR 1320.13. This information collection consists of the forms that the respondents described below, will be required to submit to SBA in order to provide the information necessary to participate in the SBA Secondary Market Guarantee Program for First Lien Position 504 Loan Pools.

The title, description and number of respondents, the estimated annual cost and hour burdens imposed on the respondents, as a result of this collection of information, are outlined below. SBA invites comments on this new information collection, particularly on: (1) Whether the proposed collection of information is necessary for the proper performance of SBA's functions, including whether the information will have a practical utility; (2) the accuracy of SBA's estimate of the burden of the proposed collection of information; (3) ways to enhance the quality, utility, and clarity of the information to be collected; and (4) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques, when appropriate, and other forms of information technology.

1. *Form Title and Purpose:* SBA Form 2401: First Lien Position 504 Loan Pool Guarantee Agreement. This is the primary agreement to be executed by all parties to each secondary market pool security transaction. It sets out the terms and conditions under which sellers will exchange portions of first lien position 504 loans in exchange for proceeds from a Pool Certificate.

Description and Estimated Number of Respondents: Approximately 50 Sellers and Pool Originators as those terms are defined in this rule.

Estimated Number of Responses: 9,000.

Frequency of Response: once per each project (response) financed.

Total Estimated Hour Burden: 27,000 based on an estimated 3 hours per response.

Total Estimated Hourly Cost to Respondents: The cost to the government estimated to be approximately $308,250.00 annually. Each request for guaranty is estimated to require .5 hours of a contractor's time at $50 per hour, times 9,000 pool applications or $225,000.00. SBA would also incur approximately $83,250.00 including .25 hour per application from a GS–13 staff analyst (GS–13 at $37 per hour) for verifying the terms of the agreement with the underlying documentation.

2. *Form Title and Purpose:* SBA Form 2404: Application to Become a Pool Originator under the SBA Secondary Market Guarantee Program for First Lien Position 504 Pools. It sets out the information necessary for SBA to make a determination on the application for participation in the program.

Description and Estimated Number of Respondents: 15 broker dealers who are interested in becoming Pool Originators.

Estimated Number of Responses (applications): 15.

Frequency of Response: one time submission—per application.

Total Estimated Hour Burden: 150 hours based on an estimated time of 10 hours per application.

Total Estimated Hourly Cost to Respondents: This form will likely be completed by an attorney (in house or outside counsel). Their estimated average annual salary is $100,000.00. Their hourly rate is calculated to be about $48.08. It is estimated that it will cost respondents $480.80 per response.

3. *Form Title and Purpose:* SBA Form 2403: Application for Pool of First Lien Position 504 Loan Interests. This form will provide SBA with details concerning each of the first lien position 504 loans the Pool Originator proposes to put into a loan pool.

Description and Estimated Number of Respondents: 15 Pool Originators.

Estimated Number of Responses (loan pools): 475.

Frequency of Response: Once per pool assembled.

Total Estimated Hour Burden: 1,425 hours based on the estimated time of 3 hours per response.

Total Estimated Hourly Cost to Respondents: The cost to the government is estimated to be approximately $17,812.00 annually. Each request for guaranty is estimated to require .5 hours of a contractor's time at $50 per hour, times 475 pool applications or $17,812.00. SBA would not be involved in the pool creation process and any review of the documents would have be done simultaneously with the review of First Lien Position 504 Loan Pool Guarantee Agreement and would not incur any expanses other than the cost for the contractor to perform the related duties.

4. *Form Title and Purpose:* SBA Form 2402: Form of Detached Assignment For U.S. Small Business Administration Guaranteed First Lien Position 504 Loan Pool Certificate. This form will be used to collect information concerning the transfer of Pool Certificates for the benefit of investors.

Description and Estimated Number of Respondents: 250 potential investors and broker dealers who will participate in the program established by this rule.

Estimated Number of Responses (loan pools): 3,000.

Frequency of Response: Once for each pool.

Total Estimated Hour Burden: 4,500 based on an estimated time of 1.5 hours per response.

Estimated Hourly Cost to Respondents: The cost to the government estimated to be approximately $37,500.00 annually. Each request for guaranty is estimated to require .25 hours of a contractor's time at $50 per hour, times 3,000 pool certificate transfer applications or $37,500.00. SBA would not be involved in the transfer transaction and would not incur any expenses other than the cost for the contractor to perform the related duties.

Regulatory Flexibility Act

Because this rule is an interim final rule, there is no requirement for SBA to prepare a Regulatory Flexibility Act (RFA) analysis. The RFA requires administrative agencies to consider the effect of their actions on small entities, small non-profit businesses, and small local governments. Pursuant to the RFA, when an agency issues a rule, the agency must prepare analysis that describes whether the impact of the rule will have a significant economic impact on a substantial number of small entities. However, the RFA requires such analysis only where notice and comment rulemaking is required.

List of Subjects in 13 CFR Part 120

Loan programs—business, Small businesses.

■ For the reasons stated in the preamble, SBA amends 13 CFR part 120 as follows:

PART 120—BUSINESS LOANS

■ 1. The authority for 13 CFR part 120 continues to read as follows:

Authority: 15 U.S.C. 634(b)(6), (b)(7), (b)(14), (h), and note, 636(a), (h) and (m), 650, 687(f), 696(3), and 697(a) and (e); Pub. L. 111–5, 123 Stat. 115.

■ 2. Add a new subpart J to read as follows:

Subpart J—Establishment of SBA Secondary Market Guarantee Program for First Lien Position 504 Loan Pools

§ 120.1700 Definitions used in subpart J.

504 financing. The loans made to a small business to fund a Project under the SBA's development company loan program authorized by Title V of the Small Business Investment Act of 1958.

Affiliate. A person or entity SBA determines to be an affiliate of a Program Participant pursuant to the application of the principles and guidelines set forth in § 121.103 of this Title.

Central Servicing Agent or CSA. The entity serving as SBA's central servicing agent for the Program.

Certified Development Company or CDC. An entity that meets the definition of a Certified Development Company as defined in § 120.10 of this Part.

Current. That no scheduled payment owed by an Obligor pursuant to a Pool Note is over 29 days past due.

First Lien Position 504 Loan. The financing provided by the First Lien Position 504 lender that is part of the 504 project financing.

First Lien Position 504 Loan Pool Guarantee Agreement. The agreement, in the form approved by SBA, wherein entities agree to participate in the forming of a Pool under the Program, available at *http://www.sba.gov/aboutsba/sbaprograms/elending/index.html/.*

Guide. The First Lien Position 504 Loan Pooling Program Guide published by SBA which provides information applicable to the Program including, among other things, requirements relating to the formation of a Pool, available at *http://www.sba.gov/aboutsba/sbaprograms/elending/index.html/.*

Liquidation Proceeds. Cash, including insurance proceeds, proceeds of any foreclosed-on property disposition, revenues received with respect to the conservation and disposition of a foreclosed-on property or repossessed collateral, including any real property securing the Pool Loan, consisting of a commercial property or residential property and any improvements thereon, and any other amounts received in connection with the liquidation of the Pool Loan, whether through Seller's sale, foreclosure sale, any offset or workout, or otherwise.

Loan Interest. The right to receive the owned portion of the principal balance of the Pool Loan together with interest thereon at a per annum rate in effect from time to time in accordance with the First Lien Position 504 Loan Pool Guarantee Agreement.

Maturity. The maturity of the Loan Interest in the Pool that has the longest remaining term of any Loan Interest in the Pool. The maturity will change from time to time due to prepayment or default on Loan Interests in the Pool.

Ongoing Guarantee Fee. An annual fee collected monthly and based on the percentage of the Pool Loan amount, pursuant to section 503(C)(3)(B)(ii) of the Recovery Act, to result in a cost of the loan guarantee of zero as determined under the Federal Credit Reform Act of 1990, as amended. The funds generated by the fee serve as a reserve to pay for program losses.

Obligor. The obligor(s) under a Pool Note.

Pool. The aggregate of Loan Interests formed into a single pool by the Pool Originator in accordance with the Program. The Pool is comprised of an unguaranteed portion and an SBA-guaranteed portion. The unguaranteed portion of the Pool backs the Pool Originator Receipt, and cannot be sold to Pool Investors. The SBA-guaranteed portion of the Pool backs the Pool Certificates sold to Pool Investors. The Seller's Loan Interest is not included in the Pool.

Pool Assembler. An entity that meets the qualifications of a Pool Assembler as set forth in section 120.630 of this Part and has been approved as such by SBA.

Pool Certificate. The document representing a beneficial fractional interest in the SBA-guaranteed portion of a Pool.

Pooled. When one or more Loan Interests in a Pool Loan has been put into a Pool.

Pooling. The transfer of one or more Loan Interests in a Pool Loan into a Pool.

Pool Investor. An entity which holds a Pool Certificate in accordance with Program Rules and Regulations.

Pool Loan. A loan that meets the Program eligibility requirements as set forth in § 120.1704 of this subpart J and has been pooled.

Pool Loan Receivables. Pool Loan payments, prepayments, or collections made in connection with the Pool Loan by the Obligor pursuant to Pool Note or any other Pool Loan documents or agreements, or by another person or entity made on behalf of any such Pool Loan obligor, and Liquidation Proceeds.

Pool Note. The document evidencing a Pool Loan.

Pool Originator. An entity approved by SBA to pool Loan Interests under the Program.

Pool Originator Receipt. The document evidencing the Pool Originator's retained ownership in a Pool it has formed under the Program.

Premier Certified Lenders Program. The program defined in § 120.845 of this Part.

Program. The program authorized by section 503 of the American Recovery and Reinvestment Act of 2009.

Program Participant. An entity that executes the First Lien Position 504 Loan Pool Guarantee Agreement as Seller, Pool Originator, or Pool Investor, and any successors or assignees thereof.

Program Participant Associate. (1) An officer, director, key employee, or holder of 20 percent or more of the value of a Program Participant's stock or debt instruments, or (2) Any individual in which one or more individuals referred to in paragraph (1) of this definition, or a spouse, or child, or sibling, or the spouse of any such individual, owns or controls at least 20 percent.

Program Preference. Any arrangement giving the Seller, Pool Originator, or a Program Associate or Affiliate of Seller or Pool Originator, a preference or benefit of proportion greater than its Loan Interest as compared to Pool Originator, Pool Investor, or SBA relating to the making, servicing, or liquidation of the Loan with respect to such things as repayment, collateral, guarantees, control, maintenance of a compensating balance, purchase of a certificate of deposit or acceptance of a separate or companion loan, without SBA's consent. Seller's agreement to grant a Pool Loan's Obligor a deferment in return for receiving more collateral on a different loan owned by Seller is an example of a preference.

Program Rules and Regulations. This subpart J, as may be amended from time to time by SBA (the Program Regulations), the First Lien Position 504 Loan Pool Guarantee Agreement, any other Program agreements signed by a Program Participant, if applicable, the Guide, the Recovery Act, and the provisions of subpart H governing Third Party Loans and Third Party Lenders.

Project. A project as defined by § 120.802 of the Part.

SBA. The United States Small Business Administration, an agency of the United States Government.

Seller. An entity that has sold a Pool Loan to a Pool Originator to be Pooled and any successor entity that has executed the First Lien Position 504 Loan Pool Guaranty Agreement pursuant to § 120.1707.

Seller's Pool Loan. The Pool Loan sold to a Pool Originator pursuant to the First Lien Position 504 Loan Pool Guarantee Agreement.

Seller Receipt. The document that evidences a Seller's Loan Interest.

Servicing Retention Amount. The amount of a Pool Loan interest payment retained by Seller for servicing the Pool Loan that is payable and calculated pursuant to the First Lien Position 504 Loan Pool Guarantee Agreement.

Weighted Average Interest Rate. The dollar-weighted average interest rate of a Pool Certificate calculated by multiplying the interest rate of each Loan Interest in the Pool by the ratio of that Loan Interest's current outstanding principal in the SBA-guaranteed portion of the Pool (that is, the portion of the Pool Loan backing the Pool Certificates) to the current aggregate or outstanding principal of each Loan Interest in the SBA-guaranteed portion of the Pool, and adding the sum of the resulting products. The Pool Certificate interest rate will fluctuate over the life of the Pool as defaults, prepayments and normal repayments applicable to Loan Interests in the Pool occur.

Weighted Average Maturity. The weighted average maturity of a Pool Certificate is a dollar weighted average maturity that is calculated by multiplying the remaining term, in months, of each Loan Interest in a Pool by the ratio of that Loan Interest's current outstanding pooled principal to the current aggregate outstanding pooled principal of all Loan Interests in the Pool, and adding the sum of the resulting products. The weighted average maturity of a Pool Certificate will fluctuate over the life of the Pool as Loan Interest defaults, prepayments and normal Loan Interest repayments occur.

§ 120.1701 Program purpose.

As authorized by the American Recovery and Reinvestment Act of 2009 (Recovery Act), SBA establishes the Program to authorize an entity to apply for SBA's guarantee of Pools comprised of portions of First Lien Position 504 Loans backing Pool Certificates to be sold to Pool Investors. The purpose of the Program is to temporarily provide a federal guarantee for Pools of First Lien Position 504 Loans to facilitate the sale of such loans and increase the liquidity of the lenders holding the loans so that the lenders can use the sale proceeds to fund more such loans. The Program's authorization expires on February 17, 2011 and the Administrator may guarantee not more than $3,000,000,000 of pools under this authority pursuant to section 503(c)(B)(iii) of the Recovery Act.

§ 120.1702 Program fee.

Ongoing Guarantee Fee. The Ongoing Guarantee Fee is payable to SBA, and it is calculated and payable monthly from the amounts received in respect of interest on Loan Interests in the SBA-guaranteed portion of a Pool. This amount is set forth in the First Lien Position 504 Loan Pool Guarantee Agreement. This fee is used to pay program losses.

§ 120.1703 Qualifications to be a Pool Originator.

(a) *Application to become Pool Originator.* The application to become a Pool Originator is available from the SBA and can be found on SBA's website. In order to qualify as a Pool Originator, an entity must send the application to the SBA and certify that it is a Pool Assembler or it:

(1) Is regulated by the appropriate agency as defined in section 3(a)(34)(G) of the Securities Exchange Act of 1934 (15 U.S.C. 78c(a)(34)(G));

(2) Meets all financial and other applicable requirements of its regulatory

authority and the Government Securities Act of 1986, as amended (Pub. L. 99–571, 100 Stat. 3208);

(3) Has the financial capability to originate acceptable pools consisting of eligible First Lien Position 504 Loans in sufficient quantity to support the issuance of Pool Certificates;

(4) Is in good standing with SBA (as the SBA determines), the Office of the Comptroller of the Currency (OCC) if it is a national bank, the Federal Deposit Insurance Corporation if it is a bank not regulated by the OCC, the Financial Institutions Regulatory Authority, if it is a member, the National Credit Union Administration if it is a credit union; and

(5) for any Pool Originator that is an SBA Lender, that the SBA Lender has satisfactory SBA performance, as determined by SBA in its sole discretion.

(b) *Approval by SBA.* An entity may not submit applications to form Pools to the CSA until SBA has approved its application to become a Pool Originator.

(c) *Conduct of business by Pool Originator.* An entity continues to qualify as a Pool Originator so long as it:

(1) Meets the eligibility standards in paragraph (a) of this section;

(2) Conducts its business in accordance with SBA regulations and accepted securities or banking industry practices, ethics, and standards;

(3) Maintains its books and records in accordance with generally accepted accounting principles or in accordance with the guidelines of the regulatory body governing its activities; and

(4) Has not been suspended or terminated from the Program by SBA.

§ 120.1704 Pool Loans eligible for Pooling.

(a) *General Pool Loan eligibility requirements.* For a First Lien Position 504 Loan to be eligible for Pooling it must:

(1) Be a loan that is:

(i) A Third Party Loan as defined in § 120.801(c)(3);

(ii) Made by a private sector lender acceptable to SBA in its sole discretion; and

(iii) Secured by a first lien on the Project Property as defined in § 120.801 of this chapter;

(2) Be part of a 504 financing that is comprised of only one Third Party Loan and one CDC 504 loan; the CDC 504 loan must be funded by a Debenture that was been sold on or after February 17, 2009;

(3) Be Current and have been Current for the six-month-period immediately prior to the date the Pool is formed or for the life of the Pool Loan, whichever time period is shorter;

(4) Have been made and closed in a commercially reasonable manner, consistent with prudent lending standards;

(5) Be part of a completed 504 financing, funded by a 504 debenture, which means that the Pool Loan must be fully disbursed and the debenture funding the related loan by a CDC must have been sold on or after February 17, 2009; and

(6) Not be:

(i) To a business deriving more than one-third of its gross annual revenue from legal gambling activities;

(ii) To a casino, gambling establishment, or casino hotel;

(iii) For financing the acquisition, construction or renovation of an aquarium, zoo, golf course, or swimming pool; or

(iv) To a business covered by a six-digit North American Industry Classification System (NAICS) code for casinos—713210 (''Casinos (Except Casino Hotels)''); casino hotels—721120 (''Casino Hotels''); other gambling institutions—713290 (''Other Gambling Industries''); golf courses—713910 (''Golf Courses and Country Clubs''); or aquariums and zoos—712130 (''Zoos and Botanical Gardens'').

(b) *SBA review of a Pool Loan prior to pool formation.* SBA has the right to review any Pool Loan before a Loan Interest in it is added to a Pool, and SBA may prohibit the Pool's formation as proposed based on SBA's review in SBA's sole discretion. In the event SBA decides to review Pool Loan documents related to a Loan Interest prior to the requested Pool formation, that Loan Interest may not be added to the Pool until SBA reviews and approves the Pool Loan for such purpose. Copies of Pool Loan documents related to underwriting and origination, and any other Pool Loan-related documents SBA may, in its sole discretion, request to review in writing, must be sent to SBA's Sacramento Pool Loan Processing Center. The Pool Originator must identify and SBA must review Pool Loan documents before a Loan Interest is added to a Pool if:

(1) The Pool Loan is to a business within NAICS code 713940 covering Fitness and Recreational Sports Centers; (If SBA determines that a Pool Loan has had any of its proceeds used for any of the restricted purposes listed above, the Pool Loan will be prohibited from being part of a Pool.)

(2) The Pool Loan was part of a 504 financing involving a 504 loan that was processed under SBA's Premier Certified Lenders Program; or

(3) The Project the Pool Loan financed included the refinancing of existing debt owed to the Seller or Third Party Lender (not including interim financing associated with the Project).

§ 120.1705 Pool formation requirements.

(a) *Initiation of Pool formation.* Only an entity approved by SBA to be a Pool Originator under the Program that continues to qualify to be a Pool Originator pursuant to this subpart may initiate the formation of a Pool. The Pool Originator creates the Pool subject to Program Rules and Regulations, including the parameters set forth in the Guide, and SBA approval.

(b) *Adjustment of Pool requirements.* SBA may adjust the Pool characteristics periodically based on program experience and market conditions and will publish a revised version of the Guide in the **Federal Register** to implement such adjustments. Any such adjustments shall not affect Pools formed prior to the adjustment.

(c) *When the Pool Originator is the Seller.* When a Pool Originator proposes to form a Pool involving a Pool Loan it owns, it must execute the First Lien Position 504 Loan Pool Guarantee Agreement as Pool Originator and as Seller and, consequently, will be subject to all applicable Program Rules and Regulations pertaining to both roles.

(d) *When the Pool Originator does not own the Pool Loan.* When a Pool Originator proposes to form a Pool involving a Pool Loan it does not own, it must purchase the Loan Interest it proposes to pool from a Seller that owns the whole Pool Loan and that has the servicing rights. The Pool Originator must purchase the Loan Interest and take it into inventory or settle the purchase of the Loan Interest through the CSA concurrently with the formation of the Pool. The entity selling the Loan Interest to the Pool Originator must execute the First Lien Position 504 Loan Pool Guarantee Agreement as Seller and, consequently, will be subject to all applicable Program Rules and Regulations pertaining to a Seller. The Pool Originator must also execute the First Lien Position 504 Loan Pool Guaranty Agreement.

(e) *What CSA must receive prior to Pool formation.* Before the CSA may carry out its responsibilities relating to the formation of a Pool, it must receive:

(1) From the Pool Originator: A properly completed First Lien Position 504 Loan Pool application form, First Lien Position 504 Loan Guarantee Agreement, and any other documentation which SBA may require, if applicable; and

(2) All cost reimbursement due and payable to the CSA prior to Pool formation owed by the Participants

participating in the formation of the Pool.

§ 120.1706 Pool Originator's retained interest in Pool.

The Pool Originator must retain an ownership interest in any Pool it has formed that is equal to at least 5% of the aggregate of the total outstanding principal balance of each Pool Loan with a Loan Interest in the Pool as calculated at the time of Pool formation. Such interest will decline with Loan Interest payments, prepayments, defaults and any other early termination. At Pool formation, the CSA will issue the Pool Originator a Pool Originator Receipt evidencing the Pool Originator's retained interest in the Pool. The Pool Originator may not sell, pledge, participate, or otherwise transfer its Pool Originator Receipt or any interest therein for the life of the Pool.

§ 120.1707 Seller's retained Loan Interest.

The Seller must retain a 15% or greater Loan Interest in each of its loans included in a Pool. At Pool formation, the CSA will issue the Seller a Seller Receipt evidencing the Seller's retained ownership in the Pool Loan. With SBA's written permission, the Seller may sell the Seller Receipt and Servicing Retention Amount in whole, but not in part, to a single entity at one time. The Seller may not sell less than 100% of the Seller Receipt and Servicing Retention Amount, and may not sell a participation interest in any portion of any of its Pooled loans. In addition, in order to complete such sale, Seller must have the purchaser of its rights to the Pool Loan execute the First Lien Position 504 Loan Pool Guarantee Agreement as Seller and deliver the executed original to the CSA.

§ 120.1708 Pool Certificates.

(a) *SBA Guarantee of Pool Certificates.* SBA guarantees to a Pool Investor the timely payment of principal and interest installments and any prepayment or other recovery of principal to which the Pool Investor is entitled. If an Obligor misses a scheduled payment pursuant to the terms of the Pool Note underlying a Loan Interest backing a Pool Certificate, SBA, through the CSA, will make advances to maintain the schedule of interest and principal payments to the Pool Investor. If SBA makes such payments, it is subrogated fully to the rights satisfied by such payment.

(b) *SBA guarantee backed by full faith and credit.* SBA's guarantee of the Pool Certificate is backed by the full faith and credit of the United States.

(c) *SBA purchase of a Loan Interest.* SBA will determine whether to purchase a Loan Interest backing a Pool Certificate with an underlying Pool Note that is 60 days or more in arrears. SBA reserves the right to purchase a Loan Interest from a Pool at any time.

(d) *Self-liquidating.* A Pool Certificate represents a fractional beneficial interest in a Pool that is self-liquidating by Pool Loan Receivables and/or SBA Loan Interest payment or redemption.

(e) *Pool Certificate form.* The CSA prepares the Pool Certificate. SBA must approve the form and terms of the Pool Certificate.

(f) *Pool Certificate registration.* A Pool Certificate must be registered with the CSA.

(g) *Face amount of Pool Certificate.* The face amount of a Pool Certificate cannot be less than a minimum amount as specified in the Guide, and the dollar amount of Pool Certificates must be in increments which SBA will specify in the Guide (except for one Pool Certificate for each Pool). SBA may change these requirements based upon an analysis of market conditions and program experience, and will publish any such change in the Federal Register.

(h) *Basis of payment for Pool Certificates.* All payments on a Pool Certificate are due pursuant to terms, conditions, and percentages set forth or referenced therein and are based on the unpaid principal balance of the Pool represented by the Pool Certificate. Any Pool Loan Receivables applicable to a Loan Interest in the SBA-guaranteed portion of a Pool will be passed through to the appropriate Pool Investors with the regularly scheduled payments to such Pool Investors.

(i) *Pool Certificate interest rate.* A Pool Certificate must have a Weighted Average Interest Rate.

(j) *Pool Certificate maturity.* A Pool Certificate must have a Maturity and a Weighted Average Maturity.

(k) *Early Pool Certificate redemption.* SBA, or the CSA on behalf of SBA, may redeem a Pool Certificate prior to its Maturity because of Obligor prepayment and/or SBA purchase of all Loan Interests in the Pool backing the Pool Certificate.

§ 120.1709 Transfers of Pool Certificates.

(a) *Transfer of Pool Certificates.* A Pool Certificate is transferable. A transfer of a Pool Certificate must comply with Article 8 of the Uniform Commercial Code of the State of New York. The seller may use any form of assignment acceptable to SBA and the CSA. The CSA may refuse to issue a Pool Certificate until it is satisfied that the documents of transfer are complete.

(b) *Transfer on CSA records.* In order for the transfer of a Pool Certificate to be effective, the CSA must reflect the transfer on its records.

(c) *Contents of letter of transmittal for Pool Certificate.* A letter of transmittal must accompany each Pool Certificate which a Pool Investor submits to the CSA for transfer. The Pool Investor must supply the following information in the letter:

(1) Pool number;

(2) Pool Certificate number;

(3) Name of purchaser of Pool Certificate;

(4) Address and tax identification number of the purchaser;

(5) Name, e-mail address and telephone number of the person handling or facilitating the transfer; and

(6) Instructions for the delivery of the new Pool Certificate.

(d) *CSA transfer cost recovery.* At the same time a Pool Investor submits a letter of transmittal for a Pool Certificate pursuant to this section, it must send to the CSA sufficient funds to cover its cost for this service. The CSA will supply the transfer information to the Pool Investor.

§ 120.1710 Central servicing of the Program.

(a) *Pool Certificates and Receipts issued at Pool formation.* As part of its role as Central Servicing Agent for the Pool, at Pool formation, CSA issues a Seller Receipt to the Seller, a Pool Originator Receipt to the Pool Originator, and a Pool Certificate to each Pool Investor.

(b) *CSA fiscal transfer responsibilities.* All Pool Loan Receivables on a Pool Loan received by the CSA must be forwarded by it to pay the Servicing Retention Amount, Ongoing Guarantee Fee, Seller Receipt, Pool Originator Receipt, Pool Certificates, any SBA-purchased Loan Interest, and any other payment applicable to the Pooling of such Pooled Loan, in accordance with Program Rules and Regulations.

(c) *Administration of the Pool Certificates.* CSA must administer each Pool Certificate. It shall maintain a registry of Pool Investors and other information as SBA requires. CSA registers all Pool Certificates. This means it issues, transfers title to, and redeems them. It shall maintain a registry of Pool Investors and other information as SBA requires. In fulfilling its obligation to keep the central registry current, the CSA may, with SBA's approval, obtain any necessary information from the parties involved in the Program.

(d) *CSA Monthly Report.* CSA must provide SBA with a list, by Pool, of each

Loan Interest with an underlying Pool Note that is 60 days or more in arrears on a monthly basis.

§ 120.1711 Suspension or termination of Program participation privileges.

(a) *Participant suspension or termination.* The SBA may suspend or terminate the privilege of a Participant, and/or any Associate or Affiliate of the Participant, to sell, purchase, broker, or deal in Pool Loans, Loan Interests, or Pool Certificates under the Program if any such Participant or its Associate or Affiliate has:

(1) Failed to comply materially with any requirement imposed by the Program Rules and Regulations or other SBA rules and regulations; or

(2) Made a material false statement or failed to disclose a material fact to SBA.

(b) *Additional rules for suspension or termination of Pool Originator.* In addition to the conditions set forth in paragraph (a) above, SBA may also suspend or terminate the Program participation privileges of a Pool Originator if the Pool Originator (and/or its Associates):

(1) Does not comply with any of the requirements in 120.1703(a) or (c);

(2) Has been revoked or suspended it from engaging in the securities business by its supervisory agency, or is under investigation for a practice which SBA considers, in its sole discretion, to be relevant to its fitness to participate in the Program;

(3) Has been indicted or otherwise formally charged with, or convicted of, a felony, or a misdemeanor which, in SBA's sole discretion, bears on its fitness to participate in the Program;

(4) Has received an adverse civil judgment that it has committed a breach of trust or a violation of a law or regulation protecting the integrity of business transactions or relationships; or

(5) Has been suspended or terminated as a Pool Assembler under 120.631.

(c) *Suspension procedures.* SBA may undertake suspension or enforcement actions under this section using the procedures set forth in § 120.1600(a).

§ 120.1712 Seller responsibilities with respect to Seller's Pool Loan.

Seller shall remain obligated for servicing and liquidating Seller's Pool Loan until the Pool Loan is repaid in full unless SBA provides written approval or notice to the contrary.

§ 120.1713 Seller's Pool Loan origination.

SBA is entitled to recover from the Seller losses incurred by SBA on its guarantee of a Pool if such losses resulted because Seller's Pool Loan was not made and closed in a commercially reasonable manner, consistent with prudent lending standards, and in accordance with any applicable Program Rules and Regulations.

§ 120.1714 Seller's Pool Loan servicing.

Subject to § 120.1718 of this subpart J, the Seller must service Seller's Pool Loan in a commercially reasonable manner, consistent with prudent lending standards, and in accordance with applicable Program Rules and Regulations. The Seller receives the Servicing Retention Amount for servicing the Seller's Pool Loan.

§ 120.1715 Seller's Pool Loan liquidation.

Subject to § 120.1718 of this subpart J, the Seller must liquidate and conduct debt collection litigation for Seller's Pool Loan in a prompt, cost-effective and commercially reasonable manner, consistent with prudent lending standards, in accordance with applicable Program Rules and Regulations, and with SBA approval of a liquidation plan and any litigation plan, and any amendment of either such a plan, if applicable.

§ 120.1716 Required SBA approval of servicing actions.

Seller shall not, without prior written consent of SBA, take the following actions with respect to Seller's Pool Loan:

(a) Make or consent to any substantial alteration in the terms (''substantial'' includes, but is not limited to, any changes to the principal amount or interest rate);

(b) Accelerate the maturity;

(c) Sue; or

(d) Waive or release any claim. Guidance on other servicing actions, some of which may need prior SBA approval, is provided in the Guide.

§ 120.1717 Seller's Pool Loan deferments.

Without the prior written consent of SBA, Seller, at the request of Obligor, may grant one deferment of Obligor's scheduled payments for a continuous period not to exceed three months of past or future installments. Seller shall immediately notify CSA of any payment deferment and that notification shall include:

(a) The SBA Pool Loan number;

(b) The Obligor's name;

(c) The terms of such deferment;

(d) The date Obligor is to resume payment; and

(e) Reconfirmation of the basis of interest calculation (e.g. 30/360 or Actual Days/365).

§ 120.1718 SBA's right to assume Seller's responsibilities.

SBA may, in its sole discretion, undertake the servicing, liquidation and/or litigation of Seller's Pool Loan at any time and, in such event, Seller must take any steps necessary to facilitate the assumption by SBA of such responsibilities, which can be transferred by SBA at its discretion to a contractor, agent or other entity, and such steps shall include, among other things, providing or assigning to SBA any documents requested by SBA within 15 calendar days of Seller's receipt of such request. SBA will notify the Obligor of the change in servicing.

§ 120.1719 SBA's right to recover from Seller.

SBA is entitled to recover from Seller any monies paid on SBA's guarantee of a Pool Certificate backed in part by Seller's Pool Loan, plus interest, if SBA in its sole discretion determines that any of the following events has occurred:

(a) Seller's improper action or inaction has put SBA at risk;

(b) Seller has failed to disclose a material fact to SBA regarding a Seller's Pool Loan in a timely manner;

(c) Seller has misrepresented a material fact to SBA regarding Seller's Pool Loan;

(d) Seller has failed to comply materially with § 120.1720 of this subpart;

(e) SBA has received a written request from Seller to terminate the SBA's guarantee on the Loan Interest in Seller's Pool Loan;

(f) Seller has failed to comply materially with Program Rules and Regulations; or

(g) Seller has failed to make, close, service or liquidate Seller's Pool Loan in a prudent manner.

§ 120.1720 SBA's right to review Pool Loan documents.

In the event that SBA purchases a Loan Interest in Seller's Pool Loan, Seller must provide to SBA copies of the Pool Loan collateral documents, Pool Loan underwriting documents, and any other documents SBA may require in writing within 15 calendar days of a written request from SBA (which SBA will review in connection with its efforts to determine if Seller is obligated to reimburse SBA pursuant to this subpart). A Seller's failure to provide the requested documentation may constitute a material failure to comply with the Program Rules and Regulations and may lead to an action for recovery under § 120.1719. SBA will also evaluate a Seller's continued participation in the Program and may restrict further sales under the Program until SBA determines that the Seller has provided sufficient documentation.

§ 120.1721 SBA's right to investigate.

SBA may undertake such investigation as it deems necessary to determine whether it is entitled to seek recovery from the Seller and Seller agrees to take whatever actions are necessary to facilitate such investigation.

§ 120.1722 SBA's offset rights.

SBA shall have the right to offset any amount owed by Lender to SBA, including, without limitation, an offset against CSA's obligation to pay Lender pursuant to any Section 504 First Mortgage Loan Pool Guarantee Agreement.

§ 120.1723 Pool Loan receivables received by Seller.

Any Pool Loan Receivables received by Seller in connection with obligations under Seller's Pool Loan must be forwarded by Seller to CSA within two business days of receipt of collected funds.

§ 120.1724 Servicing and liquidation expenses.

All ordinary and reasonable expenses of servicing and liquidating Seller's Pool Loan shall be paid by, or be recoverable from, Obligor, and all such ordinary and reasonable expenses incurred by Seller or SBA which are not recoverable from Obligor shall be shared ratably by Seller, SBA, and the Pool Originator pursuant to the applicable percentages set forth in the First Lien Position 504 Loan Pool Guarantee Agreement.

§ 120.1725 No Program Preference by Seller or Pool Originator.

The Seller and the Pool Originator must not establish a Program Preference, which is defined in 13 CFR 120.10.

§ 120.1726 Pool Certificates a Seller cannot purchase.

Neither a Seller, nor any of its Program Associates or Affiliates, may purchase a Pool Certificate that is backed by a Loan Interest in a Pool Loan that the Seller, or any of its Program Associates or Affiliates, originated or owned, and, in the event such purchase occurs, SBA's guarantee shall not be in effect with respect to any such Pool Certificate.

Dated: October 26, 2009.

Karen G. Mills,

Administrator.

[FR Doc. E9–26211 Filed 10–28–09; 11:15 am]

BILLING CODE 8025–01–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2009–1000; Directorate Identifier 2009–NM–164–AD; Amendment 39–16070; AD 2008–10–07 R1]

RIN 2120–AA64

Airworthiness Directives; Boeing Model 747–100, 747–100B, 747–100B SUD, 747–200B, 747–200C, 747–200F, 747–300, 747SR, and 747SP Series Airplanes

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Final rule; request for comments.

SUMMARY: The FAA is revising an existing airworthiness directive (AD), which applies to all Boeing Model 747–100, 747–100B, 747–100B SUD, 747–200B, 747–200C, 747–200F, 747–300, 747SR, and 747SP series airplanes. That AD currently requires revising the FAA-approved maintenance program by incorporating new airworthiness limitations (AWLs) for fuel tank systems to satisfy Special Federal Aviation Regulation No. 88 requirements. That AD also requires the initial inspection of certain repetitive AWL inspections to phase in those inspections, and repair if necessary. This AD clarifies the intended effect of the AD on spare and on-airplane fuel tank system components. This AD results from a design review of the fuel tank systems. We are issuing this AD to prevent the potential for ignition sources inside fuel tanks caused by latent failures, alterations, repairs, or maintenance actions, which, in combination with flammable fuel vapors, could result in a fuel tank explosion and consequent loss of the airplane.

DATES: This AD is effective November 16, 2009.

On June 12, 2008 (73 FR 25977, May 8, 2008), the Director of the Federal Register approved the incorporation by reference of a certain publication listed in the AD.

We must receive any comments on this AD by December 14, 2009.

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

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

For service information identified in this AD, contact Boeing Commercial Airplanes, Attention: Data & Services Management, P.O. Box 3707, MC 2H–65, Seattle, Washington 98124–2207; telephone 206–544–5000, extension 1; fax 206–766–5680; e-mail *me.boecom@boeing.com*; Internet *https://www.myboeingfleet.com*.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://www.regulations.gov*; or in person at the Docket Management Facility between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this AD, the regulatory evaluation, any comments received, and other information. The street address for the Docket Office (telephone 800–647–5527) is in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

FOR FURTHER INFORMATION CONTACT: Douglas Bryant, Aerospace Engineer, Propulsion Branch, ANM–140S, Seattle Aircraft Certification Office, FAA, 1601 Lind Avenue, SW., Renton, Washington 98057–3356; telephone (425) 917–6505; fax (425) 917–6590.

SUPPLEMENTARY INFORMATION:

Discussion

On April 28, 2008, we issued AD 2008–10–07, amendment 39–15513 (73 FR 25977, May 8, 2008). That AD applies to all Boeing Model 747–100, 747–100B, 747–100B SUD, 747–200B, 747–200C, 747–200F, 747–300, 747SR, and 747SP series airplanes. That AD requires revising the FAA-approved maintenance program by incorporating new airworthiness limitations (AWLs) for fuel tank systems to satisfy Special Federal Aviation Regulation No. 88 requirements. That AD also requires the initial inspection of certain repetitive AWL inspections to phase in those inspections, and repair if necessary. That AD resulted from a design review of the fuel tank systems. The actions specified in that AD are intended to prevent the potential for ignition sources inside fuel tanks caused by latent failures, alterations, repairs, or maintenance actions, which, in combination with flammable fuel vapors, could result in a fuel tank explosion and consequent loss of the airplane.

Critical design configuration control limitations (CDCCLs) are limitation requirements to preserve a critical ignition source prevention feature of the fuel tank system design that is necessary to prevent the occurrence of an unsafe condition. The purpose of a CDCCL is to provide instruction to retain the critical ignition source prevention feature during configuration change that may be caused by alterations, repairs, or maintenance actions. A CDCCL is not a periodic inspection.

Actions Since AD Was Issued

Since we issued that AD, we have determined that it is necessary to clarify the AD's intended effect on spare and on-airplane fuel tank system components, regarding the use of maintenance manuals and instructions for continued airworthiness.

Section 91.403(c) of the Federal Aviation Regulations (14 CFR 91.403(c) specifies the following:

> No person may operate an aircraft for which a manufacturer's maintenance manual or instructions for continued airworthiness has been issued that contains an airworthiness limitation section unless the mandatory * * * procedures * * * have been complied with.

Some operators have questioned whether existing components affected by the new CDCCLs must be reworked. We did not intend for the AD to retroactively require rework of components that had been maintained using acceptable methods before the effective date of the AD. Owners and operators of the affected airplanes therefore are not required to rework affected components identified as airworthy or installed on the affected airplanes before the required revisions of the FAA-approved maintenance program. But once the CDCCLs are incorporated into the FAA-approved maintenance program, future maintenance actions on components must be done in accordance with those CDCCLs.

FAA's Determination and Requirements of This AD

The unsafe condition described previously is likely to exist or develop on other airplanes of the same type design. For this reason, we are issuing this AD to revise AD 2008–10–07. This new AD retains the requirements of the existing AD, and adds a new note to clarify the intended effect of the AD on spare and on-airplane fuel tank system components.

Explanation of Additional Change to AD

AD 2008–10–07 allowed the use of alternative inspections, inspection intervals, and CDCCLs if they are part of a later revision of the Boeing 747–100/200/300/SP Airworthiness Limitations (AWLs) and Certification Maintenance Requirements (CMRs), D6–13747–CMR, Revision March 2008. AD 2008–10–07 also allowed use of later revisions of Boeing 747–100/200/300/SP Airworthiness Limitations (AWLs) and Certification Maintenance Requirements (CMRs), D6–13747–CMR, Revision March 2008. Those provisions have been removed from this AD. Allowing the use of ''a later revision'' of a specific service document violates Office of the Federal Register policies for approving materials that are incorporated by reference. Affected operators, however, may request approval to use an alternative inspection, inspection interval, or CDCCL that is part of a later revision of the referenced service document as an alternative method of compliance, under the provisions of paragraph (k) of this AD.

Costs of Compliance

This revision imposes no additional economic burden. The current costs for this AD are repeated for the convenience of affected operators, as follows:

There are about 308 airplanes of the affected design in the worldwide fleet. The following table provides the estimated costs, at an average labor rate of $80 per work hour, for U.S. operators to comply with this AD.

ESTIMATED COSTS

Action	Work hours	Parts	Cost per airplane	Number of U.S.-registered airplanes	Fleet cost
Maintenance program revision	8	None	$640	93	$59,520
Inspections	8	None	640	93	59,520

FAA's Justification and Determination of the Effective Date

This revision merely clarifies the intended effect on spare and on-airplane fuel tank system components, and makes no substantive change to the AD's requirements. For this reason, it is found that notice and opportunity for prior public comment for this action are unnecessary, and 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 provide you with notice and an opportunity to provide your comments before it becomes effective. However, we invite you to send any written data, views, or arguments about this AD. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2009–1000; Directorate Identifier 2009–NM–164–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 we receive about this AD.

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

For the reasons discussed above, I certify that the regulation:

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

We prepared a regulatory evaluation of the estimated costs to comply with this AD and placed it in the AD docket. *See* the **ADDRESSES** section for a location to examine the regulatory evaluation.

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 part 39 of the Federal Aviation Regulations (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 removing amendment 39–15513 (73 FR 25977, May 8, 2008) and adding the following new AD:

2008–10–07 R1 Boeing: Amendment 39–16070. Docket No. FAA–2009–1000; Directorate Identifier 2009–NM–164–AD.

Effective Date

(a) This airworthiness directive (AD) is effective November 16, 2009.

Affected ADs

(b) This AD revises AD 2008–10–07.

Applicability

(c) This AD applies to all Boeing Model 747–100, 747–100B, 747–100B SUD, 747–200B, 747–200C, 747–200F, 747–300, 747SR, and 747SP series airplanes, certificated in any category.

Note 1: This AD requires revisions to certain operator maintenance documents to include new inspections. Compliance with these inspections is required by 14 CFR 91.403(c). For airplanes that have been previously modified, altered, or repaired in the areas addressed by these inspections, the operator may not be able to accomplish the inspections described in the revisions. In this situation, to comply with 14 CFR 91.403(c), the operator must request approval for an alternative method of compliance (AMOC) according to paragraph (k) of this AD. The request should include a description of changes to the required inspections that will ensure the continued operational safety of the airplane.

Unsafe Condition

(d) This AD results from a design review of the fuel tank systems. We are issuing this AD to prevent the potential for ignition sources inside fuel tanks caused by latent failures, alterations, repairs, or maintenance actions, which, in combination with flammable fuel vapors, could result in a fuel tank explosion and consequent loss of the airplane.

Compliance

(e) You are responsible for having the actions required by this AD performed within the compliance times specified, unless the actions have already been done.

Restatement of AD 2008–10–07 With Changes to Compliance Method: Service Information Reference

(f) The term ''Revision March 2008 of Document D6–13747–CMR,'' as used in this AD, means Boeing 747–100/200/300/SP Airworthiness Limitations (AWLs) and Certification Maintenance Requirements (CMRs), D6–13747–CMR, Revision March 2008. (For the purposes of Revision March 2008 of Document D6–13747–CMR, the Model 747SR series airplane is basically a Model 747–100 series airplane with certain modifications to improve fatigue life.)

Maintenance Program Revision

(g) Before December 16, 2008, revise the FAA-approved maintenance program to incorporate the information in Section D, ''AIRWORTHINESS LIMITATIONS—SYSTEMS,'' AWLs No. 28–AWL–01 through No. 28–AWL–19 inclusive, of Revision March 2008 of Document D6–13747–CMR; except that the initial inspections required by paragraph (h) of this AD must be done at the applicable compliance time specified in that paragraph. As an optional action, AWLs No. 28–AWL–20 through No. 28–AWL–23 inclusive, as identified in Section D of Revision March 2008 of Document D6–13747–CMR, also may be incorporated into the FAA-approved maintenance program.

Initial Inspections and Repair if Necessary

(h) Do the inspections specified in Table 1 of this AD at the compliance time specified in Table 1 of this AD, and repair any discrepancy, in accordance with Section D of Revision March 2008 of Document D6–13747–CMR. The repair must be done before further flight. Accomplishing the inspections identified in Table 1 of this AD as part of an FAA-approved maintenance program before the applicable compliance time specified in Table 1 of this AD constitutes compliance with the requirements of this paragraph.

Note 2: For the purposes of this AD, a detailed inspection is: ''An intensive examination of a specific item, installation, or assembly to detect damage, failure, or irregularity. Available lighting is normally supplemented with a direct source of good lighting at an intensity deemed appropriate. Inspection aids such as mirror, magnifying lenses, etc., may be necessary. Surface cleaning and elaborate procedures may be required.''

Note 3: For the purposes of this AD, a special detailed inspection is: ''An intensive examination of a specific item, installation, or assembly to detect damage, failure, or irregularity. The examination is likely to make extensive use of specialized inspection techniques and/or equipment. Intricate cleaning and substantial access or disassembly procedure may be required.''

TABLE 1—INITIAL INSPECTIONS

AWL No.	Description	Compliance time (whichever occurs later)	
		Threshold	Grace period
28–AWL–01	A detailed inspection of external wires over the center fuel tank for damaged clamps, wire chafing, and wire bundles in contact with the surface of the center fuel tank.	Within 144 months since the date of issuance of the original standard airworthiness certificate or the date of issuance of the original export certificate of airworthiness.	Within 72 months after June 12, 2008 (the effective date of AD 2008–10–07).

TABLE 1—INITIAL INSPECTIONS—Continued

AWL No.	Description	Compliance time (whichever occurs later)	
		Threshold	Grace period
28–AWL–03	A special detailed inspection of the lightning shield to ground termination on the out-of-tank fuel quantity indicating system to verify functional integrity.	Within 144 months since the date of issuance of the original standard airworthiness certificate or the date of issuance of the original export certificate of airworthiness.	Within 24 months after June 12, 2008.
28–AWL–13	A special detailed inspection of the fault current bond of the fueling shutoff valve actuator of the center wing tank to verify electrical bond.	Within 144 months since the date of issuance of the original standard airworthiness certificate or the date of issuance of the original export certificate of airworthiness.	Within 60 months after June 12, 2008.

No Alternative Inspections, Inspection Intervals, or Critical Design Configuration Control Limitations (CDCCLs)

(i) After accomplishing the actions specified in paragraphs (g) and (h) of this AD, no alternative inspections, inspection intervals, or CDCCLs may be used unless the inspections, intervals, or CDCCLs are approved as an AMOC in accordance with the procedures specified in paragraph (k) of this AD.

Credit for Actions Done According to Previous Revisions of the Service Information

(j) Actions done before the June 12, 2008, in accordance with Boeing 747–100/200/300/SP Airworthiness Limitations (AWLs) and Certification Maintenance Requirements (CMRs), D6–13747–CMR, Revision March 2006; Revision May 2006; Revision December 2006; Revision January 2007; Revision September 2007; or Revision January 2008; are acceptable for compliance with the corresponding requirements of paragraphs (g) and (h) of this AD.

New Information

Explanation of CDCCL Requirements

Note 4: Notwithstanding any other maintenance or operational requirements, components that have been identified as airworthy or installed on the affected airplanes before the revision of the FAA-approved maintenance program, as required by paragraph (g) of this AD, do not need to be reworked in accordance with the CDCCLs. However, once the FAA-approved maintenance program has been revised, future maintenance actions on these components must be done, in accordance with the CDCCLs.

Alternative Methods of Compliance (AMOCs)

(k)(1) The Manager, Seattle Aircraft Certification Office (ACO), FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. Send information to ATTN: Douglas Bryant, Aerospace Engineer, Propulsion Branch, ANM–140S, FAA, Seattle ACO, FAA, 1601 Lind Avenue, SW., Renton, Washington 98057–3356; telephone (425) 917–6505; fax (425) 917–6590. Or, e-mail information to *9-ANM-Seattle-ACO-AMOC-Requests-faa.gov.*

(2) To request a different method of compliance or a different compliance time for this AD, follow the procedures in 14 CFR 39.19. Before using any approved AMOC on any airplane to which the AMOC applies, notify your principal maintenance inspector (PMI) or principal avionics inspector (PAI), as appropriate, or lacking a principal inspector, your local Flight Standards District Office. The AMOC approval letter must specifically reference this AD.

Material Incorporated by Reference

(l) You must use Boeing 747–100/200/300/SP Airworthiness Limitations (AWLs) and Certification Maintenance Requirements (CMRs), D6–13747–CMR, Revision March 2008, to do the actions required by this AD, unless the AD specifies otherwise.

(1) The Director of the Federal Register previously approved the incorporation by reference of Boeing 747–100/200/300/SP Airworthiness Limitations (AWLs) and Certification Maintenance Requirements (CMRs), D6–13747–CMR, Revision March 2008, on June 12, 2008 (73 FR 25977, May 8, 2008).

(2) For service information identified in this AD, contact Boeing Commercial Airplanes, Attention: Data & Services Management, P.O. Box 3707, MC 2H–65, Seattle, Washington 98124–2207; telephone 206–544–5000, extension 1; fax 206–766–5680; e-mail *me.boecom@boeing.com;* Internet *https://www.myboeingfleet.com.*

(3) You may review copies of the service information at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington. For information on the availability of this material at the FAA, call 425–227–1221 or 425–227–1152.

(4) You may also review copies of the service information that is incorporated by reference at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

Issued in Renton, Washington, on October 22, 2009.

Ali Bahrami,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. E9–26123 Filed 10–29–09; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2009–1001; Directorate Identifier 2009–NM–166–AD; Amendment 39–16071; AD 2008–04–18 R1]

RIN 2120–AA64

Airworthiness Directives; EMBRAER Model EMB–120, –120ER, –120FC, –120QC, and –120RT Airplanes

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Final rule; request for comments.

SUMMARY: We are adopting a new airworthiness directive (AD) for the products listed above that would revise an existing AD. This AD results from mandatory continuing airworthiness information (MCAI) originated by an aviation authority of another country to identify and correct an unsafe condition on an aviation product. The MCAI describes the unsafe condition as:

It has been found that former revisions of the Maintenance Review Board Report (MRBR) of the EMB–120( ) aircraft do not fully comply with some Critical Design Configuration Control Limitations (CDCCL) and Fuel System Limitations (FSL). These limitations are necessary to preclude ignition sources in the fuel system, as required by RBHA–E88/SFAR–88 (Special Federal Aviation Regulation No. 88).

* * * * *

The potential of ignition sources, in combination with flammable fuel vapors, could result in fuel tank explosions and consequent loss of the airplane. This AD requires actions that are intended to address the unsafe condition described in the MCAI.

DATES: This AD becomes effective November 16, 2009.

On April 3, 2008 (73 FR 10655, February 28, 2008), the Director of the Federal Register approved the incorporation by reference of certain publications listed in the AD.

We must receive comments on this AD by December 14, 2009.

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

- *Federal eRulemaking Portal:* Go to *http://www.regulations.gov*. Follow the instructions for submitting comments.
- *Fax:* (202) 493–2251.
- *Mail:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590.
- *Hand Delivery:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–40, 1200 New Jersey Avenue, SE., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

For service information identified in this AD, contact Empresa Brasileira de Aeronautica S.A. (EMBRAER), Technical Publications Section (PC 060), Av. Brigadeiro Faria Lima, 2170—Putim—12227–901 São Jose dos Campos—SP—BRASIL; *telephone:* +55 12 3927–5852 or +55 12 3309–0732; *fax:* +55 12 3927–7546; *e-mail: distrib@embraer.com.br; Internet: http://www.flyembraer.com*.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://www.regulations.gov*; 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 regulatory evaluation, any comments received, and other information. The street address for the Docket Operations office (telephone (800) 647–5527) is in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

FOR FURTHER INFORMATION CONTACT: Todd Thompson, Aerospace Engineer, International Branch, ANM–116, Transport Airplane Directorate, FAA, 1601 Lind Avenue, SW., Renton, Washington 98057–3356; telephone (425) 227–1175; fax (425) 227–1149.

SUPPLEMENTARY INFORMATION:

Discussion

On February 15, 2008, we issued AD 2008–04–18, Amendment 39–15390 (73 FR 10655, February 28, 2008). That AD applied to all EMBRAER Model EMB–120, –120ER, –120FC, –120QC, and –120RT airplanes. That AD required revising the Airworthiness Limitations Section of the Instructions for Continued Airworthiness to incorporate new limitations for fuel tank systems.

Critical design configuration control limitations (CDCCLs) are limitation requirements to preserve a critical ignition source prevention feature of the fuel tank system design that is necessary to prevent the occurrence of an unsafe condition. The purpose of a CDCCL is to provide instruction to retain the critical ignition source prevention feature during configuration change that may be caused by alterations, repairs, or maintenance actions. A CDCCL is not a periodic inspection.

Since we issued that AD, we have determined that it is necessary to clarify the AD's intended effect on spare and on-airplane fuel tank system components, regarding the use of maintenance manuals and instructions for continued airworthiness.

Section 91.403(c) of the Federal Aviation Regulations (14 CFR 91.403(c)) specifies the following:

> No person may operate an aircraft for which a manufacturer's maintenance manual or instructions for continued airworthiness has been issued that contains an airworthiness limitation section unless the mandatory * * * procedures * * * have been complied with.

Some operators have questioned whether existing components affected by the new CDCCLs must be reworked. We did not intend for the AD to retroactively require rework of components that had been maintained using acceptable methods before the effective date of the AD. Owners and operators of the affected airplanes therefore are not required to rework affected components identified as airworthy or installed on the affected airplanes before the required revisions of the airworthiness limitations section. But once the CDCCLs are incorporated into the airworthiness limitations section, future maintenance actions on components must be done in accordance with those CDCCLs.

FAA's Determination

This product has been approved by the aviation authority of another country, and is approved for operation in the United States. For this reason, we are issuing this AD to revise AD 2008–04–18. This new AD retains the requirements of the existing AD, and adds a new note to clarify the intended effect of the AD on spare and on-airplane fuel tank system components. We have renumbered subsequent notes accordingly.

Explanation of Additional Change to AD

AD 2008–04–18 allowed the use of later revisions of alternative inspections, inspection intervals, and CDCCLs, if they are part of a later revision of EMBRAER EMB–120 Brasilia Maintenance Review Board Report, MRB–HI–200, dated March 22, 2005. That provision has been removed from this AD. Allowing the use of ''a later revision'' of specific service documents violates Office of the Federal Register policies for approving materials that are incorporated by reference. Affected operators, however, may request approval to use a later revision of the referenced service documents as an alternative method of compliance, under the provisions of paragraph (g)(1) of this AD.

Differences Between the AD and the MCAI or Service Information

We have reviewed the MCAI and related service information and, in general, agree with their substance. But we might have found it necessary to use different words from those in the MCAI to ensure the AD is clear for U.S. operators and is enforceable. In making these changes, we do not intend to differ substantively from the information provided in the MCAI and related service information.

We might also have required different actions in this AD from those in the MCAI in order to follow FAA policies. Any such differences are highlighted in a Note within the AD.

Costs of Compliance

This revision imposes no additional economic burden. The current costs for this AD are repeated for the convenience of affected operators, as follows:

We estimate that this AD will affect about 109 products of U.S. registry. We also estimate that it will take about 1 work-hour per product to comply with the basic requirements of this AD. The average labor rate is $80 per work-hour. Based on these figures, we estimate the cost of this AD to the U.S. operators to be $8,720, or $80 per product.

FAA's Justification and Determination of the Effective Date

This revision merely clarifies the intended effect on spare and on-airplane fuel tank system components, and makes no substantive change to the AD's requirements. For this reason, it is found that notice and opportunity for prior public comment for this action are unnecessary, and 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–2009–1001; Directorate Identifier 2009–NM–166–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 we receive about this AD.

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

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 removing amendment 39–15390 (73 FR 10655, February 28, 2008) and adding the following new AD:

2008–04–18 R1 Empresa Brasileira de Aeronautica S.A. (EMBRAER): Amendment 39–16071. Docket No. FAA–2009–1001; Directorate Identifier 2009–NM–166–AD.

Effective Date

(a) This airworthiness directive (AD) becomes effective November 16, 2009.

Affected ADs

(b) This AD revises AD 2008–04–18, Amendment 39–15390.

Applicability

(c) This AD applies to all EMBRAER Model EMB–120, –120ER, –120FC, –120QC, and –120RT airplanes; certificated in any category.

Note 1: This AD requires revisions to certain operator maintenance documents to include new inspections. Compliance with these inspections is required by 14 CFR 91.403(c). For airplanes that have been previously modified, altered, or repaired in the areas addressed by these inspections, the operator may not be able to accomplish the inspections described in the revisions. In this situation, to comply with 14 CFR 91.403(c), the operator must request approval for an alternative method of compliance according to paragraph (g)(1) of this AD. The request should include a description of changes to the required inspections that will ensure the continued operational safety of the airplane.

Subject

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

Reason

(e) The mandatory continuing airworthiness information (MCAI) states:

It has been found that former revisions of the Maintenance Review Board Report (MRBR) of the EMB–120() aircraft do not fully comply with some Critical Design Configuration Control Limitations (CDCCL) and Fuel System Limitations (FSL). These limitations are necessary to preclude ignition sources in the fuel system, as required by RBHA–E88/SFAR–88 (Special Federal Aviation Regulation No. 88).

Since this condition affects flight safety, a corrective action is required. Thus, sufficient reason exists to request compliance with this AD in the indicated time limit.

The potential of ignition sources, in combination with flammable fuel vapors, could result in fuel tank explosions and consequent loss of the airplane. The corrective action is revising the Airworthiness Limitations Section (ALS) of the Instructions for Continued Airworthiness to incorporate new limitations for fuel tank systems.

Restatement of AD 2008–04–18 With Changes to Compliance Method

Actions and Compliance

(f) Unless already done, do the following actions.

(1) Within 1 month after April 3, 2008 (the effective date of AD 2008–04–18), revise the ALS of the Instructions for Continued Airworthiness to incorporate Tasks 15 to 18 of Section 6—''Part E—Fuel System Limitations,'' EMBRAER Temporary Revision No. 22–1, dated November 18, 2005, of the EMBRAER EMB–120 Brasilia Maintenance Review Board Report (MRBR), MRB–HI–200. For all tasks identified in the MRBR, the initial compliance times start from the later of the times specified in paragraphs (f)(1)(i) and (f)(1)(ii) of this AD, and the repetitive inspections must be accomplished thereafter at the interval specified in the MRBR, except as provided by paragraphs (f)(3) and (g)(1) of this AD.

(i) April 3, 2008.

(ii) The date of issuance of the original Brazilian standard airworthiness certificate or the date of issuance of the original Brazilian export certificate of airworthiness.

(2) Within 1 month after April 3, 2008, revise the ALS of the Instructions for Continued Airworthiness to incorporate the CDCCLs to include items (1) and (2), dated March 22, 2005, of Section 6—''Part D—Critical Design Configuration Control Limitation,'' of the EMBRAER EMB–120 Brasilia MRBR, MRB–HI–200.

(3) For the functional checks and detailed visual inspections, Tasks 15 to 18 of Section 6—''Part E—Fuel System Limitations,'' EMBRAER Temporary Revision No. 22–1, dated November 18, 2005, of the EMBRAER

EMB–120 Brasilia MRBR, MRB–HI–200: The initial compliance time is within 4,000 flight hours or 48 months after April 3, 2008, whichever occurs first. Thereafter those tasks must be accomplished at the repetitive interval specified in Section 6—''Part E—Fuel System Limitations,'' EMBRAER Temporary Revision No. 22–1, dated November 18, 2005, of the EMBRAER EMB–120 Brasilia MRBR, MRB–HI–200.

(4) After accomplishing the actions specified in paragraphs (f)(1) and (f)(2) of this AD, no alternative inspections, inspection intervals, or CDCCLs may be used unless the inspections, intervals, or CDCCLs are approved as an alternative method of compliance in accordance with the procedures specified in paragraph (g)(1) of this AD.

New Information

Explanation of CDCCL Requirements

Note 2: Notwithstanding any other maintenance or operational requirements, components that have been identified as airworthy or installed on the affected airplanes before the revision of the ALS, as required by paragraph (f) of this AD, do not need to be reworked in accordance with the CDCCLs. However, once the ALS has been revised, future maintenance actions on these components must be done in accordance with the CDCCLs.

FAA AD Differences

Note 3: This AD differs from the MCAI and/or service information as follows: No differences.

Other FAA AD Provisions

(g) The following provisions also apply to this AD:

(1) *Alternative Methods of Compliance (AMOCs):* The Manager, International Branch, ANM–116, Transport Airplane Directorate, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. Send information to ATTN: Todd Thompson, Aerospace Engineer, International Branch, ANM–116, Transport Airplane Directorate, FAA, 1601 Lind Avenue, SW., Renton, Washington 98057–3356; telephone (425) 227–1175; fax (425) 227–1149. Before using any approved AMOC on any airplane to which the AMOC applies, notify your principal maintenance inspector (PMI) or principal avionics inspector (PAI), as appropriate, or lacking a principal inspector, your local Flight Standards District Office. The AMOC approval letter must specifically reference this AD.

(2) *Airworthy Product:* For any requirement in this AD to obtain corrective actions from a manufacturer or other source, use these actions if they are FAA-approved. Corrective actions are considered FAA-approved if they are approved by the State of Design Authority (or their delegated agent). You are required to assure the product is airworthy before it is returned to service.

(3) *Reporting Requirements:* For any reporting requirement in this AD, under the provisions of the Paperwork Reduction Act, (44 U.S.C. 3501 *et seq.*), the Office of Management and Budget (OMB) has approved the information collection requirements and has assigned OMB Control Number 2120–0056.

Related Information

(h) Refer to MCAI Brazilian Airworthiness Directive 2007–05–02, effective June 6, 2007; EMBRAER Temporary Revision No. 22–1, dated November 18, 2005, of the EMBRAER EMB–120 Brasilia MRBR, MRB–HI–200; and Section 6—''Part D—Critical Design Configuration Control Limitation,'' of the EMBRAER EMB–120 Brasilia MRBR, MRB–HI–200; for related information.

Material Incorporated by Reference

(i) You must use EMBRAER Temporary Revision No. 22–1, dated November 18, 2005, of the EMBRAER EMB–120 Brasilia Maintenance Review Board Report, MRB–HI–200; and pages 6.III.1 and 6.III.2, dated March 22, 2005, of Section 6—''Part D—Critical Design Configuration Control Limitation,'' of the EMBRAER EMB–120 Brasilia Maintenance Review Board Report, MRB–HI–200; as applicable; to do the actions required by this AD, unless the AD specifies otherwise.

(1) The Director of the Federal Register previously approved the incorporation by reference of this service information on April 3, 2008 (73 FR 10655, February 28, 2008).

(2) For service information identified in this AD, contact Empresa Brasileira de Aeronautica S.A. (EMBRAER), Technical Publications Section (PC 060), Av. Brigadeiro Faria Lima, 2170—Putim—12227–901 São Jose dos Campos—SP—Brasil; *telephone:* +55 12 3927–5852 or +55 12 3309–0732; *fax:* +55 12 3927–7546; *e-mail: distrib@embraer.com.br;* Internet: *http://www.flyembraer.com.*

(3) You may review copies of the service information at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington. For information on the availability of this material at the FAA, call 425–227–1221 or 425–227–1152.

(4) You may also review copies of the service information that is incorporated by reference at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

Issued in Renton, Washington, on October 22, 2009.

Ali Bahrami,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. E9–26122 Filed 10–29–09; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2009–1003; Directorate Identifier 2009–SW–25–AD; Amendment 39–16064; AD 2009–22–11]

RIN 2120–AA64

Airworthiness Directives; Bell Helicopter Textron Canada Model 407 and 427 Helicopters

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Final rule; request for comments.

SUMMARY: We are adopting a new airworthiness directive (AD) for Bell Helicopter Textron Canada (Bell) Model 407 and 427 helicopters. This AD results from a mandatory continuing airworthiness information (MCAI) AD issued by the aviation authority of Canada. The MCAI AD states that, during a preflight check, it was observed that the swashplate link assembly bearing had moved in the lever race, making contact with the swashplate support. The MCAI also states that further investigation revealed that the bearing had not been staked correctly during manufacture. That condition, if not detected, could result in failure of a bearing, failure of the swashplate link assembly, and subsequent loss of control of the helicopter.

DATES: This AD becomes effective on November 16, 2009.

We must receive comments on this AD by December 29, 2009.

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

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

You may get the service information identified in this AD from Bell Helicopter Textron, Inc., P.O. Box 482, Fort Worth, TX 76101, telephone (817) 280–3391, fax (817) 280–6466, or at *http://www.bellcustomer.com/files/.*

Examining the Docket: You may examine the AD docket on the Internet at *http://www.regulations.gov* 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 economic evaluation, any comments received, and other information. The street address for the Docket Operations office (telephone (800) 647–5527) is stated in the **ADDRESSES** section of this AD. Comments will be available in the AD docket shortly after receipt.

FOR FURTHER INFORMATION CONTACT: Sharon Miles, Aviation Safety Engineer, FAA, Rotorcraft Directorate, Regulations and Guidance Group, Fort Worth, Texas 76137, telephone (817) 222–5122, fax (817) 222–5961.

SUPPLEMENTARY INFORMATION:

Discussion

Transport Canada, which is the aviation authority for Canada, has issued AD No. CF–2009–14, dated April 15, 2009 to correct an unsafe condition for Bell Model 407 helicopters, serial number (S/N) 53000 through 53887, 53890 through 53916, 53918, 53920, 53921, 53923 through 53926, and 53928; and Model 427 helicopters, S/N 56001 through 56074, 58001, and 58002, with an anti-drive link assembly, part number (P/N) 406–010–432–101, that has a serial number prefix of ''TI'' or ''TIFS.'' Transport Canada states that during a preflight check, it was observed that the swashplate link assembly bearing had moved in the lever race, making contact with the swashplate support. Transport Canada also states that further investigation revealed that the bearing had not been staked correctly during manufacture and that this situation, if not corrected, could lead to loss of control of the helicopter. You may obtain further information by examining the MCAI AD and any related service information in the AD docket.

Related Service Information

Bell has issued Alert Service Bulletin (ASB) No. 407–09–87, dated March 27, 2009, for the Model 407 helicopters and ASB No. 427–09–24, Revision A, dated March 30, 2009, for the Model 427 helicopters. The ASBs specify a one-time inspection of all anti-drive link assemblies, P/N 406–010–432–101 with a serial number prefix of ''TI'' or ''TIFS,'' to ensure that the bearing, P/N 406–310–403–101, is correctly and securely staked in the link assembly. The actions described in the MCAI AD are intended to correct the same unsafe condition as that identified in the ASBs.

FAA's Evaluation and Unsafe Condition Determination

These products have been approved by the aviation authority of Canada, and are approved for operation in the United States. Pursuant to our bilateral agreement with Canada, they have notified us of the unsafe condition described in the MCAI AD. We are issuing this AD because we evaluated all information provided by Transport Canada and determined an unsafe condition exists and is likely to exist or develop on other products of the same type design.

Differences Between This AD and the MCAI AD

This AD differs from the MCAI AD as follows:

- This AD requires compliance within 10 hours time-in-service (TIS), the MCAI AD requires compliance within the next 10 flight hours, but no later than 30 days from the effective day of the MCAI AD, which was May 6, 2009; and
- This AD does not apply to Model 427 helicopters with S/N 58001 or 58002 because those serial-numbered helicopters are not eligible for an FAA certificate of airworthiness.

Costs of Compliance

We estimate that this AD will affect about 554 helicopters of U.S. registry. We also estimate that it will take about 1 work-hour per helicopter to inspect and replace, if necessary, the bearing or the anti-drive link assembly. The average labor rate is $80 per work-hour. Required parts will cost about $400 for a bearing or $3,517 for an anti-drive link assembly, per helicopter. Based on these figures, we estimate the cost of this AD on U.S. operators will be $1,992,738 ($3,597 per helicopter), assuming that all anti-drive link assemblies are replaced.

FAA's Determination of the Effective Date

An unsafe condition exists that requires the immediate adoption of this AD. We find that the risk to the flying public justifies waiving notice and comment prior to adoption of this rule because the previously described critical unsafe condition can adversely affect the structural integrity of the helicopter and the inspection must be performed within 10 hours TIS. Therefore, we have determined that notice and opportunity for public comment before issuing this AD are impracticable and that good cause exists for making this amendment effective in fewer 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. However, we invite you to send us any written data, views, or arguments concerning this AD. Send your comments to an address listed under the **ADDRESSES** section of this AD. Include ''Docket No. FAA–2009–1003; Directorate Identifier 2009–SW–25–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 we receive about this AD.

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 product(s) 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.

Therefore, 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); and

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

We prepared an economic 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, 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 AD:

2009–22–11 Bell Helicopter Textron Canada: Amendment 39–16064. Docket No. FAA–2009–1003; Directorate Identifier 2009–SW–25–AD.

Effective Date

(a) This airworthiness directive (AD) becomes effective on November 16, 2009.

Other Affected ADs

(b) None.

Applicability

(c) This AD applies to the following model and serial-numbered helicopters with an anti-drive (swashplate) link assembly (link assembly), part number (P/N) 406–010–432–101, that has a serial number (S/N) prefix of "TI" or "TIFS", certificated in any category:

Model	Serial Nos.
407	53000 through 53887, 53890 through 53916, 53918, 53920, 53921, 53923 through 53926, and 53928.
427	56001 through 56074.

Reason

(d) The mandatory continuing airworthiness information (MCAI) AD states during a preflight check it was observed that the swashplate link assembly bearing had moved in the lever race, making contact with the swashplate support. The MCAI AD also states that further investigation revealed that the bearing had not been staked correctly during manufacture. That condition, if not detected, could result in failure of a bearing, failure of the link assembly, and subsequent loss of control of the helicopter.

Actions and Compliance

(e) Required as indicated, unless accomplished previously.

(1) Within 10 hours time-in-service (TIS), using a 10x or higher magnifying glass, inspect the link assembly and determine if the bearing, P/N 406–310–403–101, is correctly installed and properly staked in the link assembly. Also inspect to ensure that the bearing is not loose.

(2) Before further flight, replace any bearing that is incorrectly installed or improperly staked in the link assembly.

(3) Before further flight, replace the link assembly if the bearing is loose.

Differences Between This AD and the MCAI AD

(f) This AD differs from the MCAI AD as follows:

(1) This AD requires compliance within 10 hours TIS, the MCAI AD requires compliance within the next 10 flight hours, but no later than 30 days from the effective day of the MCAI AD, which was May 6, 2009; and

(2) This AD does not apply to Model 427 helicopters, S/N 58001 or 58002, because those serial-numbered helicopters are not eligible for an FAA certificate of airworthiness.

Other Information

(g) Alternative Methods of Compliance (AMOCs): The Manager, Safety Management Group, FAA, ATTN: Sharon Miles, Aviation Safety Engineer, Rotorcraft Directorate, Fort Worth, Texas 76137, telephone (817) 222–5122, fax (817) 222–5961, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19.

Related Information

(h) The following documents contain related information:

(1) Transport Canada AD No. CF–2009–14, dated April 15, 2009;

(2) Bell Helicopter Alert Service Bulletin No. 407–09–87, dated March 27, 2009; and

(3) Bell Helicopter Alert Service Bulletin No. 427–09–24, Revision A, dated March 30, 2009.

Joint Aircraft System/Component (JASC) Code

(i) JASC Code 6230: Main rotor/swashplate.

Issued in Fort Worth, Texas on October 20, 2009.

Mark R. Schilling,

Acting Manager, Rotorcraft Directorate, Aircraft Certification Service.

[FR Doc. E9–26120 Filed 10–29–09; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2007–0115; Directorate Identifier 2007–CE–080–AD; Amendment 39–16067; AD 2007–26–08 R1]

RIN 2120–AA64

Airworthiness Directives; Reims Aviation S.A. Model F406 Airplanes

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: We are rescinding an existing airworthiness directive (AD) for the products listed above. The existing AD resulted from mandatory continuing airworthiness information (MCAI) issued by an aviation authority of another country to identify and correct an unsafe condition on an aviation product. The MCAI describes the unsafe condition as:

On several occasions, leaks of the landing gear emergency blowdown bottle have been reported. Investigations revealed that the leakage was located on the nut manometer because of a design deficiency in the bottle head.

If left uncorrected, the internal bottle pressure could not be maintained to an adequate level and could result in a malfunction, failing to extend landing gears during emergency situations.

Since issuance of that AD, we have determined that the condition is not unsafe.

DATES: This AD becomes effective December 4, 2009.

ADDRESSES: You may examine the AD docket on the Internet at *http://www.regulations.gov* or in person at Document Management Facility, U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590.

FOR FURTHER INFORMATION CONTACT: Mike Kiesov, Aerospace Engineer, FAA, Small Airplane Directorate, 901 Locust, Room 301, Kansas City, Missouri 64106; *telephone:* (816) 329–4144; *fax:* (816) 329–4090.

SUPPLEMENTARY INFORMATION:

Discussion

We issued a notice of proposed rulemaking (NPRM) to amend 14 CFR part 39 to include an AD that would apply to the specified products. That NPRM was published in the **Federal Register** on July 31, 2009 (74 FR 38140), and proposed to rescind AD 2007–26–08, Amendment 39–15310 (72 FR 73258, December 27, 2007).

Since we issued AD 2007–26–08, we have reconsidered this AD with respect to the determination of an unsafe condition.

We issued AD 2007–26–08 in consideration of the MCAI from an aviation authority of another country to identify and correct an unsafe condition on an airplane. At that time, we were not aware that there were several Cessna Aircraft Company (Cessna) model airplanes equipped with the same blowdown bottle part number (P/N) 9910154–4.

Before issuing an AD on domestic products, we prepare a risk assessment of the unsafe condition. A risk assessment was done for the Cessna model airplanes. The result of that assessment was not high enough to support AD action since the system is a backup system to the primary landing gear extension system.

Based on this risk assessment, we reevaluated the existing AD against Reims Aviation Model 406 airplanes (AD 2007–26–08) and determined the condition identified in the AD is not an unsafe condition.

Comments

We gave the public the opportunity to participate in developing this AD. We received no comments on the NPRM or on the determination of the cost to the public.

Conclusion

We reviewed the available data and determined that air safety and the public interest require adopting the AD as proposed.

FAA's Determination and Requirements of the AD Rescission

We are issuing this AD rescission because we evaluated all information and determined the condition identified in the existing AD is not unsafe and the AD is not necessary.

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 DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and

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

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

Examining the AD Docket

You may examine the AD docket on the Internet at *http://www.regulations.gov;* or in person at the Docket Management Facility between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains the NPRM, the regulatory evaluation, any comments received, and other information. The street address for the Docket Office (telephone (800) 647–5527) is in the ADDRESSES section. Comments will be available in the AD docket shortly after receipt.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, 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 rescinding AD 2007–26–08, Amendment 39–15310 (72 FR 73258, December 27, 2007):

2007–26–08 R1 Reims Aviation S.A.: Amendment 39–16067; Docket No. FAA–2007–0115; Directorate Identifier 2007–CE–080–AD.

Effective Date

(a) This airworthiness directive (AD) becomes effective December 4, 2009.

Affected ADs

(b) This AD rescinds AD 2007–26–08.

Applicability

(c) This AD applies to Model F406 airplanes, all serial numbers, that are:

(1) equipped with landing gear emergency blowdown bottle part number (P/N) 9910154–4; and

(2) certificated in any category.

Issued in Kansas City, Missouri, on October 23, 2009.

Kim Smith,

Manager, Small Airplane Directorate, Aircraft Certification Service.

[FR Doc. E9–26126 Filed 10–29–09; 8:45 am]

BILLING CODE 4910–13–P

SECURITIES AND EXCHANGE COMMISSION

17 CFR Part 232

[Release Nos. 33–9077; 34–60875; 39–2468; IC–28984]

Adoption of Updated EDGAR Filer Manual

AGENCY: Securities and Exchange Commission.

ACTION: Final rule.

SUMMARY: The Securities and Exchange Commission (the Commission) is adopting revisions to the Electronic Data Gathering, Analysis, and Retrieval System (EDGAR) Filer Manual to reflect updates to the EDGAR system made in EDGAR Release 9.17. The revisions were made primarily to enforce additional XBRL validation requirements to improve the quality of XBRL exhibits; to allow filers to electronically submit the withdrawal of application for exemptive or other relief from the Investment Companies Act as submission types APP WD and APP WD/A; and, to allow filers to add Subject Company related information for the submission types F–6, F–6/A, F–6EF, and F–6POS. The revisions to the Filer Manual reflect changes within Volume I entitled EDGAR Filer Manual, Volume I: ''General Information,'' Version 8 (September 2009) and Volume

II entitled EDGAR Filer Manual, Volume II: ''EDGAR Filing,'' Version 13 (September 2009). The updated manual will be incorporated by reference into the Code of Federal Regulations.

DATES: Effective October 30, 2009 the incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of October 30, 2009.

FOR FURTHER INFORMATION CONTACT: In the Office of Interactive Disclosure for questions concerning additional XBRL validation requirements contact Jeffrey Naumann, Assistant Director of the Office of Interactive Disclosure, at (202) 551–5352; in the Division of Corporation Finance, for questions concerning Subject Company related information for the Forms F–6, F–6/A, F–6EF, and F–6POS and Form D contact Cecile Peters, Chief, Office of Information Technology, at (202) 551–3600; in the Division of Investment Management for questions on the electronic filing of submission types APP WD and APP WD/A contact Ruth Armfield Sanders, Senior Special Counsel, Office of Legal and Disclosure, at (202) 551–6989; and in the Office of Information Technology, contact Rick Heroux, at (202) 551–8800.

SUPPLEMENTARY INFORMATION: We are adopting an updated EDGAR Filer Manual, Volume I and Volume II. The Filer Manual describes the technical formatting requirements for the preparation and submission of electronic filings through the EDGAR system.[1] It also describes the requirements for filing using EDGARLink[2] and the Online Forms/XML Web site.

The Filer Manual contains all the technical specifications for filers to submit filings using the EDGAR system. Filers must comply with the applicable provisions of the Filer Manual in order to assure the timely acceptance and processing of filings made in electronic format.[3] Filers may consult the Filer Manual in conjunction with our rules governing mandated electronic filing when preparing documents for electronic submission.[4]

The EDGAR system will be upgraded to Release 9.17 on September 28, 2009 and will introduce the following changes: EDGAR will be upgraded to enforce additional XBRL validation requirements to improve the quality of XBRL exhibits. This change will enhance the validation process the EDGAR system uses to confirm compliance with the requirements in Chapter 6 of the EDGAR Filer Manual, Volume II: ''EDGAR Filing''. Minor clarifications were made to the instructions on XBRL/Interactive Data tagging.

EDGAR will allow filers, who previously submitted on EDGAR or in paper an application for exemptive or other relief from the Investment Company Act, to electronically submit the withdrawal of such application as new submission types APP WD or APP WD/A on the EDGARLink Submission Template 3.

EDGAR will allow filers to add Subject Company related information to the submission types F–6, F–6/A, F–6EF, and F–6POS. These submission types are available on EDGARLink Submission Template 1.

A minor change will be made to the online Form D to update the OMB expiration date. Minor backend processing changes are being made to ensure that online and third party Form D filings are validated consistently.

Along with adoption of the Filer Manual, we are amending Rule 301 of Regulation S–T to provide for the incorporation by reference into the Code of Federal Regulations of today's revisions. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51.

You may obtain paper copies of the updated Filer Manual at the following address: Public Reference Room, U.S. Securities and Exchange Commission, 100 F Street, NE., Room 1520, Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. We will post electronic format copies on the Commission's Web site; the address for the Filer Manual is *http://www.sec.gov/info/edgar.shtml*.

Since the Filer Manual relates solely to agency procedures or practice, publication for notice and comment is not required under the Administrative Procedure Act (APA)[5]. It follows that the requirements of the Regulatory Flexibility Act[6] do not apply.

The effective date for the updated Filer Manual and the rule amendments is October 30, 2009. In accordance with the APA[7], we find that there is good cause to establish an effective date less than 30 days after publication of these rules. The EDGAR system upgrade to Release 9.17 is scheduled to be available on September 28, 2009. The Commission believes that establishing an effective date less than 30 days after publication of these rules is necessary to coordinate the effectiveness of the updated Filer Manual with the system upgrade.

Statutory Basis

We are adopting the amendments to Regulation S–T under Sections 6, 7, 8, 10, and 19(a) of the Securities Act of 1933,[8] Sections 3, 12, 13, 14, 15, 23, and 35A of the Securities Exchange Act of 1934,[9] Section 319 of the Trust Indenture Act of 1939,[10] and Sections 8, 30, 31, and 38 of the Investment Company Act of 1940.[11]

List of Subjects in 17 CFR Part 232

Incorporation by reference, Reporting and recordkeeping requirements, Securities.

Text of the Amendment

■ In accordance with the foregoing, Title 17, Chapter II of the Code of Federal Regulations is amended as follows:

PART 232—REGULATION S–T—GENERAL RULES AND REGULATIONS FOR ELECTRONIC FILINGS

■ 1. The authority citation for part 232 continues to read in part as follows:

Authority: 15 U.S.C. 77f, 77g, 77h, 77j, 77s(a), 77z–3, 77sss(a), 78c(b), 78*l*, 78m, 78n, 78o(d), 78w(a), 78*ll*, 80a–6(c), 80a–8, 80a–29, 80a–30, 80a–37, and 7201 *et seq.*; and 18 U.S.C. 1350.

* * * * *

■ 2. Section 232.301 is revised to read as follows:

§ 232.301 EDGAR Filer Manual.

Filers must prepare electronic filings in the manner prescribed by the EDGAR Filer Manual, promulgated by the Commission, which sets out the technical formatting requirements for electronic submissions. The requirements for becoming an EDGAR Filer and updating company data are set forth in the updated EDGAR Filer Manual, Volume I: ''General Information,'' Version 8 (September 2009). The requirements for filing on EDGAR are set forth in the updated EDGAR Filer Manual, Volume II:

[1] We originally adopted the Filer Manual on April 1, 1993, with an effective date of April 26, 1993. Release No. 33–6986 (April 1, 1993) [58 FR 18638]. We implemented the most recent update to the Filer Manual on August 4, 2009. *See* Release No. 33–9058 (July 28, 2009) [74 FR 38523].

[2] This is the filer assistance software we provide filers filing on the EDGAR system.

[3] *See* Rule 301 of Regulation S–T (17 CFR 232.301).

[4] *See* Release No. 33–9058 (July 28, 2009) [74 FR 38523] in which we implemented EDGAR Release 9.16.

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

[6] 5 U.S.C. 601–612.

[7] 5 U.S.C. 553(d)(3).

[8] 15 U.S.C. 77f, 77g, 77h, 77j, and 77s(a).

[9] 15 U.S.C. 78c, 78*l*, 78m, 78n, 78o, 78w, and 78*ll*.

[10] 15 U.S.C. 77sss.

[11] 15 U.S.C. 80a–8, 80a–29, 80a–30, and 80a–37.

''EDGAR Filing,'' Version 13 (September 2009). Additional provisions applicable to Form N–SAR filers are set forth in the EDGAR Filer Manual, Volume III: ''N–SAR Supplement,'' Version 1 (September 2005). All of these provisions have been incorporated by reference into the Code of Federal Regulations, which action was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. You must comply with these requirements in order for documents to be timely received and accepted. You can obtain paper copies of the EDGAR Filer Manual from the following address: Public Reference Room, U.S. Securities and Exchange Commission, 100 F Street, NE., Room 1520, Washington, DC 20549, or call (202) 551–5850, on official business days between the hours of 10 a.m. and 3 p.m. Electronic copies are available on the Commission's Web site. The address for the Filer Manual is *http://www.sec.gov/info/edgar.shtml*. You can also inspect the document at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

By the Commission.

Dated: October 26, 2009.

Elizabeth M. Murphy,

Secretary.

[FR Doc. E9–26150 Filed 10–29–09; 8:45 am]

BILLING CODE 8011–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

26 CFR Parts 1 and 602

[TD 9469]

RIN 1545–BH54

Section 108 Reduction of Tax Attributes for S Corporations

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Final regulations.

SUMMARY: This document contains final regulations that provide guidance on the manner in which an S corporation reduces its tax attributes under section 108(b) for taxable years in which the S corporation has discharge of indebtedness income that is excluded from gross income under section 108(a). In particular, the regulations address situations in which the aggregate amount of the shareholders' disallowed section 1366(d) losses and deductions that are treated as a net operating loss tax attribute of the S corporation exceeds the amount of the S corporation's excluded discharge of indebtedness income. The regulations affect S corporations and their shareholders.

DATES: *Effective Date:* These regulations are effective on October 30, 2009.

Applicability Date: For dates of applicability, *see* § 1.108–7(f)(2).

FOR FURTHER INFORMATION CONTACT: Jennifer N. Keeney, (202) 622–3060 (not a toll-free number).

SUPPLEMENTARY INFORMATION:

Paperwork Reduction Act

The collections of information contained in these final regulations were previously reviewed and approved by the Office of Management and Budget in accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3507(d)) under control number 1545–2155. The collections of information in this final regulation are in § 1.108–7(d)(4). This information must be provided by S corporations that exclude discharge of indebtedness income from gross income under section 108(a) and shareholders of those S corporations. The information provided by shareholders will be used by S corporations to properly reduce their tax attributes under section 108(b). The information provided by S corporations will be used by shareholders of those S corporations to calculate their taxable income in succeeding taxable years.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid control number assigned by the Office of Management and Budget.

Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and return information are confidential, as required by 26 U.S.C. 6103.

Background

This document contains amendments to the Income Tax Regulations (26 CFR Part 1) under section 108 of the Internal Revenue Code (Code).

Section 61(a) provides that *gross income* means all income from whatever source derived, including (but not limited to) income from discharge of indebtedness, also known as cancellation of debt income (COD income). Section 108(a) provides an exclusion from gross income for COD income if the discharge occurs while the taxpayer is bankrupt or insolvent, or if the indebtedness discharged is qualified farm indebtedness, certain qualified real property business indebtedness, or certain qualified principal residence indebtedness. In the case of a discharge of indebtedness during insolvency, the exclusion from income is limited to the amount by which the taxpayer is insolvent. Section 108(b) provides that the taxpayer must reduce certain specified tax attributes to the extent COD income is excluded from gross income under section 108(a)(1)(A), (B), or (C). Section 108(b) also provides the order in which these tax attributes must be reduced. Unless the taxpayer makes an election under section 108(b)(5) to first reduce the basis of depreciable property, section 108(b)(2)(A) provides that the first tax attribute to be reduced is any net operating loss for the taxable year of the discharge, and any net operating loss carryover to such taxable year.

A notice of proposed rulemaking and a notice of public hearing (REG–102822–08, 2008–38 IRB 744) were published in the **Federal Register** (73 FR 45656) on August 6, 2008, proposing amendments to the regulations regarding the manner in which an S corporation reduces its tax attributes under section 108(b) for taxable years in which the S corporation has discharge of indebtedness income that is excluded from gross income under section 108(a). A public hearing on the proposed regulations was scheduled for December 8, 2008 but was cancelled because no one requested to speak. However, comments responding to the proposed regulations were received. After consideration of these comments, the proposed regulations are adopted as revised by this Treasury decision. These final regulations generally retain the provisions of the proposed regulations, with the modifications discussed in this preamble.

Summary of Comments and Explanation of Revisions

A. Allocation of Excess Losses and Deductions After Section 108(b) Tax Attribute Reduction

Section 108 provides special rules for an S corporation that has COD income. Section 108(d)(7)(A), as amended by the Job Creation and Worker Assistance Act of 2002, Public Law 107–147, provides, in part, that the rules under section 108(a) for the exclusion of COD income and under section 108(b) for the reduction of tax attributes are applied at the corporate level, including by not taking into account under section 1366(a) any amount excluded under section 108(a). Therefore, if an S corporation excludes COD income from its gross income under section 108(a), the amount excluded is applied to reduce the S corporation's tax attributes under section 108(b)(2). Under section 108(b)(4)(A), the reduction of tax attributes occurs after the S corporation's items of income, loss, deduction and credit for the taxable year of the discharge pass through to its shareholders under section 1366(a). Under section 1366(d)(1), the aggregate amount of losses and deductions a shareholder can take into account under section 1366(a) cannot exceed the shareholder's adjusted basis in the shareholder's stock in the S corporation and the shareholder's adjusted basis of any indebtedness of the S corporation to the shareholder. For purposes of the tax attribute reduction rule under section 108(b)(2), section 108(d)(7)(B) provides that any loss or deduction that is disallowed for the taxable year of the discharge under section 1366(d)(1) is treated as a net operating loss of the S corporation (deemed NOL).

Several commentators recommended that net operating losses of an S corporation carried forward from one or more C corporation taxable years (C Year NOLs) should be considered S corporation tax attributes for purposes of section 108(b)(2). The proposed regulations are silent on whether attributes such as net operating losses, capital losses, and business credits arising in a C corporation taxable year should be considered tax attributes of the S corporation for purposes of section 108(b)(2). Section 1371(b)(1) states that no carryforward, and no carryback, arising for a taxable year for which a corporation is a C corporation may be carried to a taxable year for which such corporation is an S corporation. This prohibition applies to tax attribute carryovers described in section 108(b)(2). For example, section 108(b)(2)(A) describes a net operating loss tax attribute as ''any net operating loss for the taxable year of discharge and any net operating loss carryover to such taxable year.'' Accordingly, section 1371(b)(1) prohibits an S corporation from using a C Year NOL as an S corporation tax attribute for purposes of section 108(b)(2). The same analysis applies to capital losses and business credits that arose in a C corporation taxable year. Therefore, the final regulations do not adopt this recommendation.

One commentator suggested that the final regulations clarify how the allocation rules in § 1.108–7(d)(2) of the proposed regulations apply when an S corporation, with the consent of all affected shareholders, makes an election under section 1377(a)(2) (a terminating election). Regardless of whether a terminating election is made, all disallowed losses and deductions of a shareholder under section 1366(d)(1), including disallowed losses and deductions of a terminating shareholder, are treated as an S corporation's deemed NOL. The impact of a terminating election on the allocation of the COD income, however, may result in a different allocation of the S corporation's excess deemed NOL among the shareholders. Therefore, the final regulations add an example to clarify how the allocation rules apply when a terminating election is made.

Commentators asked whether a deemed NOL described in section 108(d)(7)(B) includes any losses that are suspended under section 465 or section 469. Section 108(d)(7)(B) provides that a deemed NOL is any loss or deduction which is disallowed for the taxable year of the discharge under section 1366(d)(1). Section 1366(d)(1) specifically provides for the disallowance of losses due only to lack of basis. Therefore, a deemed NOL does not include losses suspended under section 465 or section 469.

One commentator requested that the final regulations clarify whether disallowed losses and deductions under section 1366(d)(1) of a shareholder that is an employee stock ownership plan (ESOP) are included in the S corporation's deemed NOL. Section 108(d)(7)(B) provides that any loss or deduction that is disallowed for the taxable year of the discharge under section 1366(d)(1) is treated as a deemed NOL of the S corporation. Accordingly, section 108(d)(7)(B) applies to any shareholder, including an ESOP shareholder, that has disallowed losses and deductions for the taxable year of the discharge under section 1366(d)(1).

One commentator asked whether nondeductible, noncapital expenses that reduce basis under section 1367(a)(2)(D) are treated as disallowed losses and deductions under section 1366(d)(1) for purposes of section 108(d)(7)(B). These expenses, including any that are carried over as a result of the elective ordering rule in § 1.1367–1(g) of the Income Tax Regulations, are not losses and deductions that can be taken into account by a shareholder under section 1366(a) and therefore are not included as disallowed losses and deductions under section 1366(d)(1) for purposes of section 108(d)(7)(B).

One commentator noted that in some situations, an S corporation shareholder may have a different taxable year than the S corporation. The commentator asked whether, in these situations, a shareholder determines its disallowed losses and deductions under section 1366(d)(1) for purposes of section 108(d)(7) as of the close of the S corporation's taxable year. The basis adjustments under section 1367 are determined as of the close of the S corporation's taxable year. *See* § 1.1367–1(d)(1) and § 1.1367–2(d)(1). Therefore, a shareholder's disallowed losses and deductions under section 1366(d)(1) are determined for purposes of section 108(d)(7) as of the close of the S corporation's taxable year.

Finally, one commentator recommended that the final regulations provide that all shareholders share tax attribute reductions in proportion to their ownership interests in the S corporation in all situations. The preamble to the proposed regulations noted that shareholders may be disproportionately impacted where the shareholders' respective disallowed losses or deductions are disproportionate to their respective interests. However, the disproportionate impact that occurs in certain situations is a result of the statutory provisions of section 108. Therefore, the final regulations do not adopt this recommendation. In certain situations, an S corporation may eliminate or mitigate inequitable results by making an election under section 108(b)(5) to reduce the basis of its depreciable property before reducing its net operating loss.

B. Character of Excess Deemed NOL Allocated to a Shareholder

The proposed regulations provide an ordering approach for determining the character of the amount of the S corporation's excess deemed NOL that is allocated to a shareholder. The approach in the proposed regulations is generally consistent with the ordering rules of section 108(b)(2) in that ordinary losses are reduced before capital losses. One commentator recommended that the final regulations adopt an approach that is consistent with the method for determining the character of a shareholder's losses and deductions under section 1366(d). Under this approach, the S corporation's excess deemed NOL that is allocated to a shareholder consists of a proportionate amount of each item of the shareholder's loss or deduction that is disallowed for the taxable year of the discharge under section 1366(d)(1). After considering this comment, the IRS and Treasury have decided to adopt this approach in the final regulations.

C. Information Sharing Requirements

The proposed regulations require a shareholder of an S corporation that excludes COD income from its gross income in a taxable year to report to the S corporation the amount of the shareholder's losses and deductions that are disallowed for the taxable year of the discharge under section 1366(d)(1) (shareholder-information reporting requirement). The proposed regulations also require the S corporation to report to its shareholders the amount of any excess deemed NOL that is allocated to a shareholder (S corporation-information reporting requirement). Commentators recommended changes to the shareholder-information reporting requirement to minimize dependence on information furnished by shareholders who provide (intentionally or unintentionally) incorrect information or on shareholders who fail to furnish this information. One commentator explained that as a practical matter, an S corporation often maintains records for its shareholders and may possess all the requisite information to determine the amount of a shareholder's suspended loss under section 1366(d). Another commentator requested that the final regulations provide consequences for shareholders who do not comply with the shareholder-information reporting requirement or who provide incorrect information.

After considering these comments, the final regulations modify the shareholder-information reporting requirement to alleviate the dependence on shareholders who fail to furnish information or who provide incorrect information. The final regulations provide that in certain situations, the S corporation may rely on its own books and records as well as other information available to the S corporation to determine a shareholder's disallowed losses or deductions under section 1366(d)(1), provided that the S corporation knows that the amount reported by the shareholder is inaccurate, or the information, as provided, appears to be incomplete or incorrect. The final regulations do not adopt any special rules to provide for consequences to shareholders who either fail to report this information to the S corporation or report incorrect information to the S corporation. However, the IRS and Treasury note that section 6037(c) requires that a shareholder of an S corporation, on the shareholder's return, treat a ''subchapter S item'' in a manner consistent with the S corporation return. The IRS and Treasury believe that the S corporation's excess deemed NOL that is allocated to a shareholder is a ''subchapter S item'' for purposes of section 6037(c) and that the consequences of failure to comply with section 6037(c) are sufficient to encourage shareholders to cooperate with the S corporation in order to avoid inconsistencies between the S corporation's return and the shareholder's return.

Effective/Applicability Date

The final regulations apply to discharges of indebtedness occurring on or after October 30, 2009.

Special Analyses

It has been determined that this Treasury decision is not a significant regulatory action as defined in Executive Order 12866. Therefore, a regulatory assessment is not required. It also has been determined that section 553(b) of the Administrative Procedure Act (5 U.S.C. chapter 5) does not apply to these regulations. It is hereby certified that the collection of information contained in these regulations will not have a significant economic impact on a substantial number of small entities. This certification is based on the fact that the collection burden imposed on S corporations and their shareholders is minimal in that it requires S corporations and their shareholder(s) to share information that shareholders already maintain to determine their respective tax liabilities. Moreover, it should take an S corporation or a shareholder no more than one hour to satisfy the information sharing requirements in these regulations. Finally, the collection burden imposed applies only to S corporations that are required to reduce their tax attributes under section 108(b) of the Code—a group estimated to be less than 1 percent of all existing S corporations. Therefore, a regulatory flexibility analysis under the Regulatory Flexibility Act (5 U.S.C. chapter 6) is not required. Pursuant to section 7805(f) of the Code, the notice of proposed rulemaking that preceded these regulations was submitted to the Chief Counsel for Advocacy of the Small Business Administration for comment on its impact on small business.

Drafting Information

The principal author of these regulations is Jennifer N. Keeney, Office of the Associate Chief Counsel (Passthroughs and Special Industries). However, other personnel from the IRS and Treasury participated in their development.

List of Subjects

26 CFR Part 1

Income taxes, Reporting and recordkeeping requirements.

26 CFR Part 602

Reporting and recordkeeping requirements.

Adoption of Amendments to the Regulations

■ Accordingly, 26 CFR part 1 and part 602 are amended as follows:

PART 1—INCOME TAXES

■ **Paragraph 1.** The authority citation for part 1 continues to read in part as follows:

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

■ **Par. 2.** Section 1.108–7 is amended by:

■ 1. Redesignating paragraphs (d) and (e) as paragraphs (e) and (f), respectively.

■ 2. Adding new paragraph (d).

■ 3. Adding paragraph (e) *Example 5, Example 6,* and *Example 7* to newly-redesignated paragraph (e).

■ 4. Revising newly-redesignated paragraph (f).

The additions and revision read as follows:

§ 1.108–7 Reduction of attributes.

* * * * *

(d) *Special rules for S corporations*—(1) *In general.* If an S corporation excludes COD income from gross income under section 108(a)(1)(A), (B), or (C), the amount excluded shall be applied to reduce the S corporation's tax attributes under paragraph (a)(1) of this section. For purposes of paragraph (a)(1)(i) of this section, the aggregate amount of the shareholders' losses or deductions that are disallowed for the taxable year of the discharge under section 1366(d)(1), including disallowed losses or deductions of a shareholder that transfers all of the shareholder's stock in the S corporation during the taxable year of the discharge, is treated as the net operating loss tax attribute (deemed NOL) of the S corporation for the taxable year of the discharge.

(2) *Allocation of excess losses or deductions*—(i) *In general.* If the amount of an S corporation's deemed NOL exceeds the amount of the S corporation's COD income that is excluded from gross income under section 108(a)(1)(A), (B), or (C), the excess deemed NOL shall be allocated to the shareholder or shareholders of the S corporation as a loss or deduction that is disallowed under section 1366(d) for the taxable year of the discharge.

(ii) *Multiple shareholders*—(A) *In general.* If an S corporation has multiple shareholders, to determine the amount of the S corporation's excess deemed NOL to be allocated to each shareholder under paragraph (d)(2)(i) of this section, calculate with respect to each shareholder the shareholder's excess amount. The shareholder's excess amount is the amount (if any) by which the shareholder's losses or deductions disallowed under section 1366(d)(1) (before any reduction under paragraph (a)(1) of this section) exceed the amount of COD income that would have been taken into account by that shareholder under section 1366(a) had the COD income not been excluded under section 108(a).

(B) *Shareholders with a shareholder's excess amount.* Each shareholder that has a shareholder's excess amount, as determined under paragraph (d)(2)(ii)(A) of this section, is allocated an amount equal to the S corporation's excess deemed NOL multiplied by a fraction, the numerator of which is the shareholder's excess amount and the denominator of which is the sum of all shareholders' excess amounts.

(C) *Shareholders with no shareholder's excess amount.* If a shareholder does not have a shareholder's excess amount as determined in paragraph (d)(2)(ii)(A) of this section, none of the S corporation's excess deemed NOL shall be allocated to that shareholder.

(iii) *Terminating shareholder.* Any amount of the S corporation's excess deemed NOL allocated under paragraph (d)(2) of this section to a shareholder that had transferred all of the shareholder's stock in the corporation during the taxable year of the discharge is permanently disallowed under § 1.1366–2(a)(5), unless the transfer of stock is described in section 1041(a). If the transfer of stock is described in section 1041(a), the amount of the S corporation's excess deemed NOL allocated to the transferor under paragraph (d)(2) of this section shall be treated as a loss or deduction incurred by the corporation in the succeeding taxable year with respect to the transferee. *See* section 1366(d)(2)(B).

(3) *Character of excess losses or deductions allocated to a shareholder.* The character of an S corporation's excess deemed NOL that is allocated to a shareholder under paragraph (d)(2) of this section consists of a proportionate amount of each item of the shareholder's loss or deduction that is disallowed for the taxable year of the discharge under section 1366(d)(1).

(4) *Information requirements.* If an S corporation excludes COD income from gross income under section 108(a) for a taxable year, each shareholder of the S corporation during the taxable year of the discharge must report to the S corporation the amount of the shareholder's losses and deductions that are disallowed for the taxable year of the discharge under section 1366(d)(1), even if that amount is zero. If a shareholder fails to report the amount of the shareholder's losses and deductions that are disallowed for the taxable year of the discharge under section 1366(d)(1) to the S corporation, or if the S corporation knows that the amount reported by the shareholder is inaccurate, or if the information, as reported, appears to be incomplete or incorrect, the S corporation may rely on its own books and records, as well as other information available to the S corporation, to determine the amount of the shareholder's losses and deductions that are disallowed for the taxable year of the discharge under section 1366(d)(1), provided that the S corporation knows or reasonably believes that its information presents an accurate reflection of the shareholder's disallowed losses and deductions under section 1366(d)(1). The S corporation must report to each shareholder the amount of the S corporation's excess deemed NOL that is allocated to that shareholder under paragraph (d)(2) of this section, even if that amount is zero, in accordance with applicable forms and instructions.

(e) * * *

Example 5. (i) *Facts.* During the entire calendar year 2009, A, B, and C each own equal shares of stock in X, a calendar year S corporation. As of December 31, 2009, A, B, and C each have a zero stock basis and X does not have any indebtedness to A, B, or C. For the 2009 taxable year, X excludes from gross income $45,000 of COD income under section 108(a)(1)(A). The COD income (had it not been excluded) would have been allocated $15,000 to A, $15,000 to B, and $15,000 to C under section 1366(a). For the 2009 taxable year, X has $30,000 of losses and deductions that X passes through pro rata to A, B, and C in the amount of $10,000 each. The losses and deductions that pass through to A, B, and C are disallowed under section 1366(d)(1). In addition, B has $10,000 of section 1366(d) losses from prior years and C has $20,000 of section 1366(d) losses from prior years. A's ($10,000), B's ($20,000) and C's ($30,000) combined $60,000 of disallowed losses and deductions for the taxable year of the discharge are treated as a current year net operating loss tax attribute of X under section 108(d)(7)(B) (deemed NOL) for purposes of the section 108(b) reduction of tax attributes.

(ii) *Allocation.* Under section 108(b)(2)(A), X's $45,000 of excluded COD income reduces the $60,000 deemed NOL to $15,000. Therefore, X has a $15,000 excess net operating loss (excess deemed NOL) to allocate to its shareholders. Under paragraph (d)(2)(ii)(C) of this section, none of the $15,000 excess deemed NOL is allocated to A because A's section 1366(d) losses and deductions immediately prior to the section 108(b)(2)(A) reduction ($10,000) do not exceed A's share of the excluded COD income for 2008 ($15,000). Thus, A has no shareholder's excess amount. Each of B's and C's respective section 1366(d) losses and deductions immediately prior to the section 108(b)(2)(A) reduction exceed each of B's and C's respective shares of the excluded COD income for 2008. B's excess amount is $5,000 ($20,000 − $15,000) and C's excess amount is $15,000 ($30,000 − $15,000). Therefore, the total of all shareholders' excess amounts is $20,000. Under paragraph (d)(2) of this section, X will allocate $3,750 of the $15,000 excess deemed NOL to B ($15,000 × $5,000/$20,000) and $11,250 of the $15,000 excess deemed NOL to C ($15,000 × $15,000/$20,000). These amounts are treated as losses and deductions disallowed under section 1366(d)(1) for the taxable year of the discharge. Accordingly, at the beginning of 2010, A has no section 1366(d)(2) carryovers, B has $3,750 of carryovers, and C has $11,250 of carryovers.

(iii) *Character.* Immediately prior to the section 108(b)(2)(A) reduction, B's $20,000 of section 1366(d) losses and deductions consisted of $8,000 of long-term capital losses, $7,000 of section 1231 losses, and $5,000 of ordinary losses. After the section 108(b)(2)(A) tax attribute reduction, X will allocate $3,750 of the excess deemed NOL to B. Under paragraph (d)(3) of this section, the $3,750 excess deemed NOL allocated to B consists of $1,500 of long-term capital losses (($8,000/$20,000) × $3,750), $1,312.50 of section 1231 losses (($7,000/$20,000) × $3,750), and $937.50 of ordinary losses (($5,000/$20,000) × $3,750). As a result, at the beginning of 2010, B's $3,750 of section 1366(d)(2) carryovers consist of $1,500 of long-term capital losses, $1,312.50 of section 1231 losses, and $937.50 of ordinary losses.

Example 6. (i) A and B each own 50 percent of the shares of stock in X, a calendar year S corporation. On March 1, 2009, X realizes $12,000 of COD income and excludes this amount from gross income under section 108(a)(1)(A) for X's 2009 taxable year. On June 30, 2009, A sells all of her shares of stock in X to C in a transfer not described in section 1041(a). X does not make a terminating election under section 1377(a)(2). The COD income (had it not been excluded) would have been allocated $3,000 to A, $6,000 to B, and $3,000 to C under section 1366(a). Prior to the section 108(b)(2)(A) reduction, for the taxable year of the discharge the shareholders have disallowed losses and deductions under section 1366(d) (including disallowed losses carried over to the current year under section 1366(d)(2)) in the following amounts: A—$5,000, B—$13,000, and C—$2,000. The combined $20,000 of disallowed losses and deductions for the taxable year of the discharge are treated as a current year net operating loss tax attribute of X under section 108(d)(7)(B) (deemed NOL).

(ii) Under section 108(b)(2)(A), X's $12,000 of excluded COD income reduces the $20,000 deemed NOL to $8,000. Therefore, X has an $8,000 excess net operating loss (excess deemed NOL) to allocate to its shareholders. Under paragraph (d)(2)(ii)(C) of this section, none of the $8,000 excess deemed NOL is allocated to C because C's section 1366(d) losses and deductions immediately prior to the section 108(b)(2)(A) reduction ($2,000) do not exceed C's share of the excluded COD income for 2008 ($3,000). However, each of A's and B's respective section 1366(d) losses and deductions immediately prior to the section 108(b)(2)(A) reduction exceed each of A's and B's respective shares of the excluded COD income for 2009. A's excess amount is $2,000 ($5,000 − $3,000) and B's excess amount is $7,000 ($13,000 − $6,000). Therefore, the total of all shareholders' excess amounts is $9,000. Under paragraph (d)(2) of this section, X will allocate $1,777.78 of the $8,000 excess deemed NOL to A ($8,000 × $2,000/$9,000) and $6,222.22 of the $8,000 excess deemed NOL to B ($8,000 × $7,000/$9,000). However, because A transferred all of her shares of stock in X in a transaction not described in section 1041(a), A's $1,777.78 of section 1366(d) losses and deductions are permanently disallowed under paragraph (d)(2)(iii) of this section. Accordingly, at the beginning of 2010, B has $6,222.22 of section 1366(d)(2) carryovers and C has no section 1366(d)(2) carryovers.

Example 7. The facts are the same as in *Example 6,* except that X, with the consent of A and C, makes a terminating election under section 1377(a)(2) upon A's sale of her stock in X to C. Therefore, the COD income (had it not been excluded) would have been allocated $6,000 to A, $6,000 to B, and $0 to C. Under paragraph (d)(2)(ii)(C) of this section, none of the $8,000 excess deemed NOL is allocated to A because A's section 1366(d) losses and deductions immediately prior to the section 108(b)(2)(A) reduction ($5,000) do not exceed A's share of the excluded COD income for 2009 ($6,000). However, each of B's and C's respective section 1366(d) losses and deductions immediately prior to the section 108(b)(2)(A) reduction exceed each of B's and C's respective shares of the excluded COD income for 2009. B's excess amount is $7,000 ($13,000 − $6,000), C's excess amount is $2,000 ($2,000 − $0). Therefore, the total of all shareholders' excess amounts is $9,000. Under paragraph (d)(2) of this section, X will allocate $6,222.22 of the $8,000 excess deemed NOL to B ($8,000 × $7,000/$9,000) and $1,777.78 of the $8,000 excess deemed NOL to C. Accordingly, at the beginning of 2010, B has $6,222.22 of section 1366(d)(2) carryovers and C has $1,777.78 of section 1366(d)(2) carryovers.

(f) *Effective/applicability date*—(1) Paragraphs (a), (b), (c), and *Examples 1, 2, 3,* and *4* of paragraph (e) of this section apply to discharges of indebtedness occurring on or after May 10, 2004.

(2) Paragraph (d) and *Examples 5, 6,* and *7* of paragraph (e) of this section apply to discharges of indebtedness occurring on or after October 30, 2009.

PART 602—OMB CONTROL NUMBERS UNDER THE PAPERWORK REDUCTION ACT

■ **Par. 3.** The authority citation for part 602 continues to read as follows:

Authority: 26 U.S.C. 7805.

■ **Par. 4.** In § 602.101, paragraph (b) is amended by adding the following entry in numerical order to the table to read as follows:

§ 602.101 OMB Control numbers.

* * * * *

(b) * * *

CFR part or section where identified and described	Current OMB control No.
* * *	*
1.108–7	1545–2155
* * *	*

Approved: October 21, 2009.

Linda E. Stiff,

Deputy Commissioner for Services and Enforcement.

Michael Mundaca,

Acting Assistant Secretary of the Treasury (Tax Policy).

[FR Doc. E9–26152 Filed 10–29–09; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF DEFENSE

Office of the Secretary

[DoD–2006–OS–0033; RIN 0790–AI26]

32 CFR Part 311

Office of the Secretary of Defense and Joint Staff Privacy Program

AGENCY: Department of Defense.

ACTION: Final rule.

SUMMARY: This rule revises 32 CFR part 311 to update Office of the Secretary of Defense (OSD) and Joint Staff (JS) policy, assigns responsibilities, and prescribes procedures for the effective administration of the Privacy Act (PA) Program in OSD and JS. This rule supplements and implements 32 CFR part 310, the DoD Privacy Program.

DATES: *Effective Date:* This rule is effective November 30, 2009.

FOR FURTHER INFORMATION CONTACT: Cindy Allard, 703–588–6830.

SUPPLEMENTARY INFORMATION: A proposed rule published in the **Federal Register** on January 23, 2007 (72 FR 2819–2823). No comments were received.

The following has been included in the final rule based on internal comments received on the corresponding DoD administrative instruction: A reordering of some sections was accomplished to facilitate readability. A new section ''OSD/JS Privacy Office Processes'' was added to define the role of the OSD/JS Privacy Office in the program.

Executive Order 12866, ''Regulatory Planning and Review''

It has been certified that 32 CFR part 311 does not:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy; a section of the economy; productivity; competition; jobs; the environment; public health or safety; or State, local, or tribunal 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 12866, as amended by Executive Order 13422.

Sec. 202, Pub. L. 104–4, ''Unfunded Mandates Reform Act''

It has been certified that 32 CFR part 311 does not contain a Federal mandate that may result in the expenditure by State, local and tribunal governments, in aggregate, or by the private sector, of $100 million or more in any one year.

Public Law 96–354, ''Regulatory Flexibility Act'' (5 U.S.C. 601)

It has been certified that 32 CFR part 311 is not subject to the Regulatory Flexibility Act (5 U.S.C. 601) because it would not, if promulgated, have a significant economic impact on a substantial number of small entities. The rule implements the procedures for the effective administration of the Privacy Act Program in OSD and the JS.

Public Law 96–511, ''Paperwork Reduction Act'' (44 U.S.C. Chapter 35)

It has been certified that 32 CFR part 311 does not impose reporting or recordkeeping requirements under the Paperwork Reduction Act of 1995.

Executive Order 13132, ''Federalism''

It has been certified that 32 CFR part 311 does not have federalism implications, as set forth in Executive Order 13132. This rule does not have substantial direct effects on:

(1) The States;

(2) The relationship between the National Government and the States; or

(3) The distribution of power and responsibilities among the various levels of Government.

List of Subjects in 32 CFR Part 311

Privacy Act.

■ Accordingly, 32 CFR part 311 is revised to read as follows:

PART 311—OFFICE OF THE SECRETARY OF DEFENSE AND JOINT STAFF PRIVACY PROGRAM

Sec.

Authority: 5 U.S.C. 552a.

§ 311.1. Purpose.

This part revises 32 CFR part 311 to update Office of the Secretary of Defense (OSD) and Joint Staff (JS) policy, assigns responsibilities, and prescribes procedures for the effective administration of the Privacy Program in OSD and the JS. This part supplements and implements part 32 CFR part 310, the DoD Privacy Program.

§ 311.2. Applicability.

This part:

(a) Applies to OSD, the Office of the Chairman of the Joint Chiefs of Staff and the Joint Staff, and all other activities serviced by Washington Headquarters Services (WHS) that receive privacy program support from OSD/JS Privacy Office, Executive Services Directorate (ESD), WHS (hereafter referred to collectively as the ''WHS-Serviced Components).''

(b) Covers systems of records maintained by the WHS-Serviced Components and governs the maintenance, access, change, and release information contained in those systems of records, from which information about an individual is retrieved by a personal identifier.

§ 311.3. Definitions.

(a) *Access.* The review of a record or a copy of a record or parts thereof in a system of records by any individual.

(b) *Computer matching program.* A program that matches the personal records in computerized databases of two or more Federal agencies.

(c) *Disclosure.* The transfer of any personal information from a system of records by any means of communication (such as oral, written, electronic, mechanical, or actual review) to any person, private entity, or Government Agency, other than the subject of the record, the subject's designated agent or the subject's legal guardian.

(d) *Individual.* A living person who is a citizen of the United States or an alien lawfully admitted for permanent residence. The parent of a minor or the legal guardian of any individual also may act on behalf of an individual. Members of the United States Armed Forces are ''individuals.'' Corporations, partnerships, sole proprietorships, professional groups, businesses, whether incorporated or unincorporated, and other commercial entities are not ''individuals'' when acting in an entrepreneurial capacity with the Department of Defense but are ''individuals'' otherwise (*e.g.,* security clearances, entitlement to DoD privileges or benefits, *etc.*).

(e) *Individual access.* Access to information pertaining to the individual by the individual or his or her designated agent or legal guardian.

(f) *Maintain.* To maintain, collect, use, or disseminate records contained in a system of records.

(g) *Personal information.* Information about an individual that identifies, links, relates, or is unique to, or describes him or her, *e.g.,* a social security number; age; military rank; civilian grade; marital status; race; salary; home/office phone numbers; other demographic, biometric, personnel, medical, and financial information, *etc.* Such information also is known as *personally identifiable information* (*i.e.,* information which can be used to distinguish or trace an individual's identity, such as their name, social security number, date and place of birth, mother's maiden name, biometric records, including any other personal information which is linked or linkable to a specified individual).

(h) *Record.* Any item, collection, or grouping of information, whatever the storage media (*e.g.,* paper, electronic, *etc.*), about an individual that is maintained by a WHS-Serviced Component, including, but not limited to, his or her education, financial transactions, medical history, criminal or employment history, and that contains his or her name, or the identifying number, symbol, or other identifying particular assigned to the individual, such as a finger or voice print or a photograph.

(i) *System manager.* A WHS-Serviced Component official who has overall responsibility for a system of records. The system manager may serve at any level in OSD. Systems managers are indicated in the published systems of records notices. If more than one official is indicated as a system manager, initial responsibility resides with the manager at the appropriate level (*i.e.,* for local records, at the local activity).

(j) *System of records.* A group of records under the control of a WHS-Serviced Component from which personal information about an individual is retrieved by the name of the individual or by some other identifying number, symbol, or other identifying particular assigned, that is unique to the individual.

§ 311.4. Policy.

It is DoD policy, in accordance with 32 CFR part 310, that:

(a) Personal information contained in any system of records maintained by any DoD organization shall be safeguarded. To the extent authorized by section 552a of title 5, United States Code, commonly known and hereafter referred to as the ''Privacy Act'' and Appendix I of Office of Management and Budget Circular No. A–130 (available at *http://www.whitehouse.gov/omb/assets/omb/circulars/a130/a130trans4.pdf*), an individual shall be permitted to know what existing records pertain to him or her consistent with 32 CFR part 310.

(b) Each office maintaining records and information about individuals shall ensure that this data is protected from unauthorized collection, use, dissemination and/or disclosure of personal information. These offices shall permit individuals to have access to and have a copy made of all or any portion of records about them, except as provided in 32 CFR 310.17 and 310.18. The individuals will also have an opportunity to request that such records be amended as provided by 32 CFR 310.19 . Individuals requesting access to their records shall receive concurrent consideration under section 552 of title 5, United States Code (commonly known and hereafter referred to as the ''Freedom of Information Act'').

(c) Necessary records of a personal nature that are individually identifiable will be maintained in a manner that complies with the law and DoD policy. Any information collected by WHS-Serviced Components must be as accurate, relevant, timely, and complete as is reasonable to ensure fairness to the individual. Adequate safeguards must be provided to prevent misuse or unauthorized release of such information, consistent with the Privacy Act.

§ 311.5. Responsibilities.

(a) The Director, WHS, under the authority, direction, and control of the

Director, Administration and Management, shall:

(1) Direct and administer the OSD/JS Privacy Program for the WHS-Serviced Components.

(2) Ensure implementation of and compliance with standard and procedures established in 32 CFR part 310.

(3) Coordinate with the WHS General Counsel on all WHS-Serviced Components denials of appeals for amending records and review actions to confirm denial of access to records.

(4) Provide advice and assistance to the WHS-Serviced Components on matters pertaining to the Privacy Act.

(5) Direct the OSD/JS Privacy Office to implement all aspects of 32 CFR part 310 as directed in § 311.7 of this part.

(b) The Heads of the WHS-Serviced Components shall:

(1) Designate an individual in writing as the point of contact for Privacy Act matters and advise the Chief, OSD/JS Privacy Office, of names of officials so designated.

(2) Designate an official in writing to deny initial requests for access to an individual's records or changes to records and advise the Chief, OSD/JS Privacy Office of names of officials so designated.

(3) Provide opportunities for appointed personnel to attend periodic Privacy Act training.

(4) Report any new record system, or changes to an existing system, to the Chief, OSD/JS Privacy Office at least 90 days before the intended use of the system.

(5) Formally review each system of records notice on a biennial basis and update as necessary.

(6) In accordance with 32 CFR 310.12, include appropriate Federal Acquisition Regulation clause (48 CFR 24.104) in all contracts that provide for contractor personnel to access WHS-Serviced Component records systems covered by the Privacy Act.

(7) Review all implementing guidance prepared by the WHS-Serviced Components as well as all forms or other methods used to collect information about individuals to ensure compliance with 32 CFR part 310.

(8) Establish administrative processes in WHS-Serviced Component organizations to comply with the procedures listed in this part and 32 CFR part 310.

(9) Coordinate with WHS General Counsel on all proposed denials of access to records.

(10) Provide justification to the OSD/JS Privacy Office when access to a record is denied in whole or in part.

(11) Provide the record to the OSD/JS Privacy Office when the initial denial of a request for access to such record has been appealed by the requester or at the time of initial denial if an appeal seems likely.

(12) Maintain an accurate administrative record documenting the actions resulting in a denial for access to a record or for the correction of a record. The administrative record should be maintained so it can be relied upon and submitted as a complete record of proceedings if litigation occurs in accordance with 32 CFR part 310.

(13) Ensure all personnel are aware of the requirement to take appropriate Privacy Act training as required by 32 CFR part 310 and the Privacy Act.

(14) Forward all requests for access to records received directly from an individual to the OSD/JS Freedom of Information Act Requester Service Center for processing under 32 CFR part 310 and 32 CFR part 286.

(15) Maintain a record of each disclosure of information (other than routine use) from a system of records as required by 32 CFR part 310.

§ 311.6. Procedures.

(a) *Publication of Notice in the* **Federal Register.** (1) A notice shall be published in the **Federal Register** of any record system meeting the definition of a system of records in 32 CFR 310.4.

(2) The Heads of the WHS-Serviced Component shall submit notices for new or revised systems of records to the Chief, OSD/JS Privacy Office, for review at least 90 days prior to desired implementation.

(3) The Chief, OSD/JS Privacy Office shall forward completed notices to the Defense Privacy Office (DPO) for review in accordance with 32 CFR 310.30. Publication in the **Federal Register** starts a 30-day comment window which provides the public with an opportunity to submit written data, views, or arguments to the DPO for consideration before a system of record is established or modified.

(b) *Access to Systems of Records Information.* (1) As provided in the Privacy Act, records shall be disclosed only to the individual they pertain to and under whose individual name or identifier they are filed, unless exempted by the provisions in 32 CFR 310.31. If an individual is accompanied by a third party, the individual shall be required to furnish a signed access authorization granting the third party access according to 32 CFR 310.17.

(2) Individuals seeking access to records that pertain to themselves, and that are filed by name or other personal identifier, may submit the request in person or by mail, in accordance with these procedures:

(i) Any individual making a request for access to records in person shall provide personal identification to the appropriate system owner, as identified in the system of records notice published in the **Federal Register**, to verify the individual's identity according to 32 CFR 310.17.

(ii) Any individual making a request for access to records by mail shall address such request to the OSD/JS FOIA Requester Service Center, Office of Freedom of Information, 1155 Pentagon, Washington, DC 20301–1155. To verify his or her identity, the requester shall include either a signed notarized statement or an unsworn declaration in the format specified by 32 CFR part 286.

(iii) All requests for records shall describe the record sought and provide sufficient information to enable the material to be located (*e.g.,* identification of system of records, approximate date it was initiated, originating organization, and type of document).

(iv) All requesters shall comply with the procedures in 32 CFR part 310 for inspecting and/or obtaining copies of requested records.

(v) If the requester is not satisfied with the response, he or she may file a written appeal as provided in paragraph (f)(8) of this section. The requester must provide proof of identity by showing a driver's license or similar credentials.

(3) There is no requirement that an individual be given access to records that are not in a group of records that meet the definition of a system of records in the Privacy Act. (For an explanation of the relationship between the Privacy Act and the Freedom of Information Act, and for guidelines to ensure requesters are given the maximum amount of information authorized by both Acts, *see* 32 CFR part 310.17

(4) Granting access to a record containing personal information shall not be conditioned upon any requirement that the individual state a reason or otherwise justify the need to gain access.

(5) No verification of identity shall be required of an individual seeking access to records that are otherwise available to the public.

(6) Individuals shall not be denied access to a record in a system of records about themselves because those records are exempted from disclosure under 32 CFR part 286. Individuals may only be denied access to a record in a system of records about themselves when those records are exempted from the access provisions of 32 CFR 310.26.

(7) Individuals shall not be denied access to their records for refusing to disclose their Social Security Number (SSN), unless disclosure of the SSN is required by statute, by regulation adopted before January 1, 1975, or if the record's filing identifier and only means of retrieval is by SSN (Privacy Act, note).

(c) *Access to Records or Information Compiled for Law Enforcement Purposes.*

(1) Requests are processed under 32 CFR part 310 and 32 CFR part 286 to give requesters a greater degree of access to records on themselves.

(2) Records (including those in the custody of law enforcement activities) that have been incorporated into a system of records exempted from the access conditions of 32 CFR part 310, will be processed in accordance with 32 CFR 286.12. Individuals shall not be denied access to records solely because they are in the exempt system. They will have the same access that they would receive under 32 CFR part 286. (*See also* 32 CFR 310.17.)

(3) Records systems exempted from access conditions will be processed under 32 CFR 310.26 or 32 CFR 286.12, depending upon which regulation gives the greater degree of access. (*See also* 32 CFR 310.17.)

(4) Records systems exempted from access under 32 CFR 310.27 that are temporarily in the hands of a non-law enforcement element for adjudicative or personnel actions, shall be referred to the originating agency. The requester will be informed in writing of this referral.

(d) *Access to Illegible, Incomplete, or Partially Exempt Records.* (1) An individual shall not be denied access to a record or a copy of a record solely because the physical condition or format of the record does not make it readily available (*e.g.,* deteriorated state or on magnetic tape). The document will be prepared as an extract, or it will be exactly recopied.

(2) If a portion of the record contains information that is exempt from access, an extract or summary containing all of the information in the record that is releasable shall be prepared.

(3) When the physical condition of the record makes it necessary to prepare an extract for release, the extract shall be prepared so that the requester will understand it.

(4) The requester shall be informed of all deletions or changes to records.

(e) *Access to Medical Records.* (1) Medical records shall be disclosed to the individual and may be transmitted to a medical doctor named by the individual concerned.

(2) The individual may be charged reproduction fees for copies or records as outlined in 32 CFR 310.20.

(f) *Amending and Disputing Personal Information in Systems of Records.*

(1) The Head of a WHS-Serviced Component, or designated official, shall allow individuals to request amendment to their records to the extent that such records are not accurate, relevant, timely, or complete.

(2) Requests shall be submitted in person or by mail to the office designated in the system of records notice. They should contain, as a minimum, identifying information to locate the record, a description of the items to be amended, and the reason for the change. Requesters shall be required to provide verification of their identity as stated in paragraphs (b)(2)(i) and (b)(2)(ii) of this section to ensure that they are seeking to amend records about themselves and not, inadvertently or intentionally, the records of others.

(3) Requests shall not be rejected nor required to be resubmitted unless additional information is essential to process the request.

(4) The appropriate system manager shall mail a written acknowledgment to an individual's request to amend a record within 10 workdays after receipt. Such acknowledgment shall identify the request and may, if necessary, request any additional information needed to make a determination. No acknowledgment is necessary if the request can be reviewed and processed and if the individual can be notified of compliance or denial within the 10-day period. Whenever practical, the decision shall be made within 30 working days. For requests presented in person, written acknowledgment may be provided at the time the request is presented.

(5) The Head of a WHS-Serviced Component, or designated official, shall promptly take one of three actions on requests to amend the records:

(i) If the WHS-Serviced Component official agrees with any portion or all of an individual's request, he or she will proceed to amend the records in accordance with existing statutes, regulations, or administrative procedures and inform the requester of the action taken in accordance with 32 CFR 310.19. The WHS-Serviced Component official shall also notify all previous holders of the record that the amendment has been made and shall explain the substance of the correction.

(ii) If the WHS-Serviced Component official disagrees with all or any portion of a request, the individual shall be informed promptly of the refusal to amend a record, the reason for the refusal, and the procedure to submit an appeal as described in paragraph (f)(8) of this section.

(iii) If the request for an amendment pertains to a record controlled and maintained by another Federal agency, the request shall be referred to the appropriate agency and the requester advised of this.

(6) When personal information has been disputed by the requestor, the Head of a WHS-Serviced Component, or designated official, shall:

(i) Determine whether the requester has adequately supported his or her claim that the record is inaccurate, irrelevant, untimely, or incomplete.

(ii) Limit the review of a record to those items of information that clearly bear on any determination to amend the record, and shall ensure that all those elements are present before a determination is made.

(7) If the Head of a WHS-Serviced Component, or designated official, after an initial review of a request to amend a record, disagrees with all or any portion of the request to amend a record, he or she shall:

(i) Advise the individual of the denial and the reason for it.

(ii) Inform the individual that he or she may appeal the denial.

(iii) Describe the procedures for appealing the denial, including the name and address of the official to whom the appeal should be directed. The procedures should be as brief and simple as possible.

(iv) Furnish a copy of the justification of any denial to amend a record to the OSD/JS Privacy Office.

(8) If an individual disagrees with the initial WHS-Serviced Component determination, he or she may file an appeal. If the record is created and maintained by a WHS-Serviced Component, the appeal should be sent to the Chief, OSD/JS Privacy Office, WHS, 1155 Defense Pentagon, Washington, DC 20301–1155.

(9) If, after review, the Chief, OSD/JS Privacy Office, determines the system of records should not be amended as requested, the Chief, OSD/JS Privacy Office, shall provide a copy of any statement of disagreement to the extent that disclosure accounting is maintained in accordance with 32 CFR 310.25 and shall advise the individual:

(i) Of the reason and authority for the denial.

(ii) Of his or her right to file a statement of the reason for disagreeing with the OSD/JS Privacy Office's decision.

(iii) Of the procedures for filing a statement of disagreement.

(iv) That the statement filed shall be made available to anyone the record is disclosed to, together with a brief statement by the WHS-Serviced Component summarizing its reasons for refusing to amend the records.

(10) If the Chief, OSD/JS Privacy Office, determines that the record should be amended in accordance with the individual's request, the WHS-Serviced Component shall amend the record, advise the individual, and inform previous recipients where a disclosure accounting has been maintained in accordance with 32 CFR 310.25.

(11) All appeals should be processed within 30 workdays after receipt by the proper office. If the Chief, OSD/JS Privacy Office, determines that a fair and equitable review cannot be made within that time, the individual shall be informed in writing of the reasons for the delay and of the approximate date the review is expected to be completed.

(g) *Disclosure of Disputed Information.* (1) If the OSD/JS Privacy Office determines the record should not be amended and the individual has filed a statement of disagreement under paragraph (f)(8) of this section, the WHS-Serviced Component shall annotate the disputed record so it is apparent to any person to whom the record is disclosed that a statement has been filed. Where feasible, the notation itself shall be integral to the record. Where disclosure accounting has been made, the WHS-Serviced Component shall advise previous recipients that the record has been disputed and shall provide a copy of the individual's statement of disagreement in accordance with 32 CFR 310.21.

(i) This statement shall be maintained to permit ready retrieval whenever the disputed portion of the record is disclosed.

(ii) When information that is the subject of a statement of disagreement is subsequently disclosed, the WHS-Serviced Component designated official shall note which information is disputed and provide a copy of the individual's statement.

(2) The WHS-Serviced Component shall include a brief summary of its reasons for not making a correction when disclosing disputed information. Such statement shall normally be limited to the reasons given to the individual for not amending the record.

(3) Copies of the WHS-Serviced Component summary will be treated as part of the individual's record; however, it will not be subject to the amendment procedure outlined in paragraph (f) of this section.

(h) *Penalties.* (1) *Civil Action.* An individual may file a civil suit against the WHS-Serviced Component or its employees if the individual feels certain provisions of the Privacy Act have been violated.

(2) *Criminal Action.* (i) Criminal penalties may be imposed against an officer or employee of a WHS-Serviced Component for these offenses listed in the Privacy Act:

(A) Willful unauthorized disclosure of protected information in the records;

(B) Failure to publish a notice of the existence of a record system in the **Federal Register**; and

(C) Requesting or gaining access to the individual's record under false pretenses.

(ii) An officer or employee of a WHS-Serviced Component may be fined up to $5,000 for a violation as outlined in paragraphs (h)(2)(i)(A) through (h)(2)(i)(C) of this section.

(i) *Litigation Status Sheet.* Whenever a complaint citing the Privacy Act is filed in a U.S. District Court against the Department of Defense, a WHS-Serviced Component, or any employee of a WHS-Serviced Component, the responsible system manager shall promptly notify the OSD/JS Privacy Office, which shall notify the DPO. The litigation status sheet in Appendix H of 32 CFR part 310 provides a standard format for this notification. (The initial litigation status sheet shall, as a minimum, provide the information required by items 1 through 6). A revised litigation status sheet shall be provided at each stage of the litigation. When a court renders a formal opinion or judgment, copies of the judgment or opinion shall be provided to the OSD/JS Privacy Office with the litigation status sheet reporting that judgment or opinion.

(j) *Computer Matching Programs.* 32 CFR 310.52 prescribes that all requests for participation in a matching program (either as a matching agency or a source agency) be submitted to the DPO for review and compliance. The WHS-Serviced Components shall submit a courtesy copy to the OSD/JS Privacy Office at the time of transmittal to the DPO.

§ 311.7. OSD/JS Privacy Office Processes.

The OSD/JS Privacy Office shall:

(a) Exercise oversight and administrative control of the OSD/JS Privacy Program for the WHS-Serviced Components.

(b) Provide guidance and training to the WHS-Serviced Components as required by 32 CFR 310.37.

(c) Collect and consolidate data from the WHS-Serviced Components and submit reports to the DPO, as required by 32 CFR 310.40 or otherwise requested by the DPO.

(d) Coordinate and consolidate information for reporting all record systems, as well as changes to approved systems, to the DPO for final processing to the Office of Management and Budget, the Congress, and the **Federal Register**, as required by 32 CFR part 310.

(e) In coordination with DPO, serve as the appellate authority for the WHS-Serviced Components when a requester appeals a denial for access as well as when a requester appeals a denial for amendment or initiates legal action to correct a record.

(f) Refer all matters about amendments of records and general and specific exemptions under 32 CFR 310.19, 310.28 and 310.29 to the proper WHS-Serviced Components.

Dated: October 26, 2009.

Patricia L. Toppings,

OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. E9–26183 Filed 10–29–09; 8:45 am]

BILLING CODE 5001–06–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R03–OAR–2009–0034; FRL–8975–2]

Approval and Promulgation of Air Quality Implementation Plans; Maryland; Clean Air Interstate Rule

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is approving State Implementation Plan (SIP) revisions submitted by the State of Maryland, with the exception of its 2009 nitrogen oxides (NO_X) ozone season and NO_X annual allocations, its 2009 set-aside allocations and the Compliance Supplement Pool (CSP) allocations. The revisions establish budget trading programs for nitrogen oxides (NO_X) annual, NO_X ozone season, and sulfur dioxides (SO_2) annual emissions to address the requirements of EPA's Clean Air Interstate Rule (CAIR). Maryland will meet its CAIR requirements by participating in the EPA-administered regional cap-and-trade program for NO_X annual, NO_X ozone season, and SO_2 annual emissions. EPA is determining that the SIP revisions fully implement the CAIR requirements for Maryland. Although the DC Circuit found CAIR to be flawed, the rule was remanded without vacatur and thus remains in

place. Thus, EPA is continuing to take action on CAIR SIPs as appropriate. CAIR, as promulgated, requires States to reduce emissions of SO_2 and NO_X that significantly contribute to, or interfere with maintenance of, the national ambient air quality standards (NAAQS) for fine particulates and/or ozone in any downwind state. CAIR establishes budgets for SO_2 and NO_X for States that contribute significantly to nonattainment in downwind States and requires the significantly contributing States to submit SIP revisions that implement these budgets. States have the flexibility to choose which control measures to adopt to achieve the budgets, including participation in EPA-administered cap-and-trade programs addressing SO_2, NO_X annual, and NO_X ozone season emissions. In the SIP revisions that EPA is approving, Maryland will meet CAIR requirements by participating in these cap-and-trade programs. EPA is approving the SIP revisions, with the exceptions noted, as fully implementing the CAIR requirements for Maryland. Consequently, this action will also cause the CAIR Federal Implementation Plans (CAIR FIPs) concerning SO_2, NO_X annual, and NO_X ozone season emissions by Maryland sources to be automatically withdrawn.

DATES: *Effective Date:* The final rule is effective on October 30, 2009.

ADDRESSES: EPA has established a docket for this action under Docket ID Number EPA–R03–OAR–2009–0034. All documents in the docket are listed in the *http://www.regulations.gov* Web site. Although listed in the electronic docket, some information is not publicly available, i.e., confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy for public inspection during normal business hours at the Air Protection Division, U.S. Environmental Protection Agency, Region III, 1650 Arch Street, Philadelphia, Pennsylvania 19103. Copies of the State submittal are available at the Maryland Department of the Environment, 1800 Washington Boulevard, Suite 705, Baltimore, Maryland, 21230.

FOR FURTHER INFORMATION CONTACT: Marilyn Powers, (215) 814–2308, or by e-mail at *powers.marilyn@epa.gov.*

SUPPLEMENTARY INFORMATION:

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I. What Action Did EPA Propose?

On August 20, 2009 (74 FR 42038), EPA published a notice of proposed rulemaking (NPR) for the State of Maryland. No comments were received. The NPR proposed approval of revisions to the Maryland SIP that addresses EPA's CAIR requirements. The formal SIP revisions were submitted by Maryland on October 24, 2007 and June 30, 2008.

II. Summary of Maryland SIP Revision

On October 24, 2007, the Maryland Department of the Environmental (MDE) submitted a full CAIR SIP revision to meet the requirements of CAIR, which was promulgated on May 12, 2005 (70 FR 25162), and subsequently revised on April 28, 2006, and December 13, 2006. The SIP revision consisted of new Maryland rule COMAR 26.11.28—Clean Air Interstate Rule (Maryland revision #07–14). On June 30, 2008, MDE submitted a SIP revision that amended Regulations .01 to .07 of COMAR 26.11.28 (Maryland revision #08–08). The regulations address all the requirements of the 40 CFR part 96 model rules set forth in the May 12, 2005 CAIR rulemaking.

On August 20, 2009 (74 FR 27731), EPA published an NPR to approve Maryland's CAIR SIP revisions, with the exception of its 2009 NO_X ozone season and NO_X annual allocations, its 2009 set-aside allocations and the CSP allocations. A detailed discussion of the CAIR requirements, the CAIR history (including the CAIR remand), Maryland's CAIR submittals, and EPA's rationale for approval of Maryland's CAIR SIP revisions may be found in the NPR and will not be repeated here.

EPA notes that, in *North Carolina,* 531 F.3d at 916–21, the Court determined, among other things, that the State SO_2 and NO_X budgets established in CAIR were arbitrary and capricious.[1] However, as discussed above, the Court also decided to remand CAIR but to leave the rule in place in order to ''temporarily preserve the environmental values covered by CAIR'' pending EPA's development and promulgation of a replacement rule that remedies CAIR's flaws. *North Carolina,* 550 F.3d at 1178. EPA had indicated to the Court that development and promulgation of a replacement rule would take about two years. *Reply in Support of Petition for Rehearing or Rehearing en Banc* at 5 (filed Nov. 17, 2008 in *North Carolina* v. *EPA,* Case No. 05–1224, D.C. Cir.). The process at EPA of developing a proposal that will undergo notice and comment and result in a final replacement rule is ongoing. In the meantime, consistent with the Court's orders, EPA is implementing CAIR by approving State SIP revisions that are consistent with CAIR (such as the provisions setting State SO_2 and NO_X budgets for the CAIR trading programs) in order to ''temporarily preserve'' the environmental benefits achievable under the CAIR trading programs.

[1] The Court also determined that the CAIR trading programs were unlawful (*id.* at 906–8) and that the treatment of title IV allowances in CAIR was unlawful (*id.* at 921–23). For the same reasons that EPA is approving the provisions of Maryland's SIP revision that use the SO_2 and NO_X budgets set in CAIR, EPA is also approving, as discussed below, Maryland's SIP revision to the extent the SIP revision adopts the CAIR trading programs, including the provisions, addressing applicability, allowance allocations, and use of title IV allowances.

III. What Is the Final Action?

EPA is approving Maryland's CAIR SIP revisions submitted on October 24, 2007 and June 30, 2008, with the exception of its 2009 NO_X ozone season and NO_X annual allocations, its 2009 set-aside allocations and the CSP allocations. Under the SIP revisions, Maryland will participate in the EPA-administered cap-and-trade programs for NO_X annual, NO_X ozone season, and SO_2 annual emissions. The SIP revisions meet the applicable requirements in 40 CFR 51.123(o) and (aa), with regard to NO_X annual and NO_X ozone season emissions, and 40 CFR 51.124(o), with regard to SO_2 emissions. As a consequence of the SIP approval, the CAIR FIPs for Maryland are automatically withdrawn, in accordance with the automatic withdrawal provisions of EPA's November 2, 2007 rulemaking (72 FR 62338). The automatic withdrawal is reflected in the rule text that accompanies this notice and deletes and reserves the provisions in Part 52 that establish the CAIR FIPs for Maryland sources.

IV. What Is the Effective Date?

EPA finds that there is good cause for this approval to become effective upon publication because a delayed effective date is unnecessary due to the nature of the approval, which allows the State, as indicated in the NPR for this rulemaking, to use its own methodology for distribution of allowances from its set aside pool. The expedited effective date for this action is authorized under both 5 U.S.C. 553(d)(1), which provides that rule actions may become effective less than 30 days after publication if the rule ''grants or recognizes an exemption or relieves a restriction'' and section 5 U.S.C. 553(d)(3), which allows an effective date less than 30 days after publication ''as otherwise provided by the agency for good cause found and published with the rule.''

CAIR SIP approvals relieve states and CAIR sources within states from being subject to provisions in the CAIR FIPs that otherwise would apply to them, allowing states to implement CAIR based on their SIP-approved state rule. The relief from these obligations is sufficient reason to allow an expedited effective date of this rule under 5 U.S.C. 553(d)(1). In addition, Maryland's relief from these obligations provides good cause to make this rule effective immediately upon publication, pursuant to 5 U.S.C. 553(d)(3). The purpose of the 30-day waiting period prescribed in 5 U.S.C. 553(d) is to give affected parties a reasonable time to adjust their behavior and prepare before the final rule takes effect. Where, as here, the final rule relieves obligations rather than imposes obligations, affected parties, such as the State of Maryland and CAIR sources within the State, do not need time to adjust and prepare before the rule takes effect.

V. Statutory and Executive Order Reviews

A. General Requirements

Under the Clean Air Act, 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 action merely approves state law as meeting Federal requirements and does not impose additional requirements beyond those imposed by state law. For that reason, this action:

- Is not a ''significant regulatory action'' subject to review by the Office of Management and Budget under Executive 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 Clean Air Act; 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.

B. Submission to Congress and the Comptroller General

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

C. Petitions for Judicial Review

Under section 307(b)(1) of the Clean Air Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by December 29, 2009. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action to approve Maryland's CAIR rules may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2).)

List of Subjects in 40 CFR Part 52

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

Dated: October 20, 2009.

William C. Early,

Acting Regional Administrator, Region III.

■ 40 CFR part 52 is amended as follows:

PART 52—[AMENDED]

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

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

Subpart V—Maryland

■ 2. In § 52.1070, the table in paragraph (c) is amended by adding an entry for COMAR 26.11.28 after the existing entry for COMAR 26.11.27 to read as follows:

§ 52.1070 Identification of plan.

* * * * *

(c) * * *

EPA-APPROVED REGULATIONS IN THE MARYLAND SIP

Code of Maryland administrative regulations (COMAR) citation	Title/subject	State effective date	EPA approval date	Additional explanation/ citation at 40 CFR 52.1100
* * * * * * *				
26.11.28 Clean Air Interstate Rule				
26.11.28.01	Definitions	6/16/08	10/30/09 [Insert page number where the document begins].	
26.11.28.02	Incorporation by Reference	6/16/08	10/30/09 [Insert page number where the document begins].	
26.11.28.03	Affected Units and General Requirements.	6/16/08	10/30/09 [Insert page number where the document begins].	
26.11.28.04	Requirements for New Affected Trading Units and NO_X Set Aside Pool.	6/16/08	10/30/09 [Insert page number where the document begins].	
26.11.28.05	NO_X Allowances for Renewable Energy Projects and Consumers of Electric Power.	6/16/08	10/30/09 [Insert page number where the document begins].	
26.11.28.06	NO_X Allowances To Be Distributed to Consumers of Electric Power.	6/16/08	10/30/09 [Insert page number where the document begins].	
26.11.28.07	Distribution of Unused NO_X Allowances in the Set Aside Pool.	6/16/08	10/30/09 [Insert page number where the document begins].	
26.11.28.08	Allocation of NO_X Allowances	6/16/08	10/30/09 [Insert page number where the document begins].	Annual and Ozone Season Allocations start in 2010 instead of 2009.
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§ 52.1084 [Removed and Reserved]

■ 3. Section 52.1084 is removed and reserved.

§ 52.1085 [Removed and Reserved]

■ 4. Section 52.1085 is removed and reserved.

[FR Doc. E9–26090 Filed 10–29–09; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R09–OAR–2009–0371; FRL–8970–6]

Revisions to the California State Implementation Plan, Northern Sierra Air Quality Management District and San Joaquin Valley Unified Air Pollution Control District

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is finalizing approval of revisions to the Northern Sierra Air Quality Management District (NSAQMD) and San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) portions of the California State Implementation Plan (SIP). These revisions were proposed in the **Federal Register** on July 13, 2009, and concern volatile organic compound (VOC) emissions from asphalt paving, gasoline bulk storage tanks, and gasoline dispensing stations. We are approving local rules that regulate these emission sources under the Clean Air Act as amended in 1990 (CAA or the Act).

DATES: *Effective Date:* This rule is effective on November 30, 2009.

ADDRESSES: EPA has established docket number EPA–R09–OAR–2009–0371 for this action. The index to the docket is available electronically at *http://www.regulations.gov* and in hard copy at EPA Region IX, 75 Hawthorne Street, San Francisco, California. While all documents in the docket are listed in the index, some information may be publicly available only at the hard copy location (e.g., copyrighted material), and some may not be publicly available in either location (e.g., CBI). To inspect the hard copy materials, please schedule an appointment during normal business hours with the contact listed in the **FOR FURTHER INFORMATION CONTACT** section.

FOR FURTHER INFORMATION CONTACT: Mae Wang, EPA Region IX, (415) 947–4124, *wang.mae@epa.gov.*

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

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I. Proposed Action

On July 13, 2009 (74 FR 33397), EPA proposed to approve the following rules into the California SIP:

Local agency	Rule No.	Rule title	Adopted or amended	Submitted
NSAQMD	227	Cutback and Emulsified Asphalt Paving Materials	11/27/06	03/07/08
SJVUAPCD	4621	Gasoline Transfer into Stationary Storage Containers, Delivery Vessels, and Bulk Plants.	12/20/07	03/07/08
SJVUAPCD	4622	Gasoline Transfer into Motor Vehicle Fuel Tanks	12/20/07	03/07/08

Local agency	Rule No.	Rule title	Adopted or amended	Submitted
SJVUAPCD	4651	Soil Decontamination Operations	9/20/07	03/07/08

We proposed to approve these rules because we determined that they complied with the relevant CAA requirements. Our proposed action contains more information on the rules and our evaluation.

II. Public Comments and EPA Responses

EPA's proposed action provided a 30-day public comment period. During this period, we did not receive any comments.

III. EPA Action

No comments were submitted that change our assessment that the submitted rules comply with the relevant CAA requirements. Therefore, as authorized in section 110(k)(3) of the Act, EPA is fully approving these rules into the California SIP.

IV. Statutory and Executive Order Reviews

Under the Clean Air Act, 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 action merely approves State law as meeting Federal requirements and does not impose additional requirements beyond those imposed by State law. For that reason, this action:

- Is not a ''significant regulatory action'' subject to review by the Office of Management and Budget under Executive 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 Clean Air Act; 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.

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

Under section 307(b)(1) of the Clean Air Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by December 29, 2009. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements (see section 307(b)(2)).

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements, Volatile organic compounds.

Dated: September 23, 2009.

Jane Diamond,

Acting Regional Administrator, Region IX.

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

PART 52—[AMENDED]

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

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

Subpart F—California

■ 2. Section 52.220 is amended by adding paragraphs (c)(354)(i)(E)(*6*), (c)(354)(i)(E)(*7*), (c)(354)(i)(E)(*8*), and (c)(354)(G) to read as follows:

§ 52.220 Identification of plan.

* * * * *

(c) * * *

(354) * * *

(i) * * *

(E) * * *

(*6*) Rule 4621, ''Gasoline Transfer into Stationary Storage Containers, Delivery Vessels, and Bulk Plants,'' amended on December 20, 2007.

(*7*) Rule 4622, ''Gasoline Transfer into Motor Vehicle Fuel Tanks,'' amended on December 20, 2007.

(*8*) Rule 4651, ''Soil Decontamination Operations,'' amended on September 20, 2007.

* * * * *

(G) Northern Sierra Air Quality Management District.

(*1*) Rule 227, ''Cutback and Emulsified Asphalt Paving Materials,'' adopted on November 27, 2006.

* * * * *

[FR Doc. E9–26178 Filed 10–29–09; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

44 CFR Part 62

[Docket ID FEMA–2009–0009]

RIN 1660–AA64

Technical Amendment; Federal Emergency Management Agency's Claims Appeals

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Final rule.

SUMMARY: By this final rule, the Federal Emergency Management Agency (FEMA) is making an address change in FEMA's National Flood Insurance Program Claims Appeals regulations.

DATES: This final rule is effective October 30, 2009.

ADDRESSES: A copy of this rule is available electronically on the Federal eRulemaking Portal at *http://www.regulations.gov.* To the far right of that page is a heading entitled ''Keyword.'' Type ''FEMA–2009–0009'' under the ''Keyword'' heading. The next screen will provide the ''Search Results.'' Scroll down until you see the tabs: ''View By Relevance'' and ''View By Docket.'' Select one of the tabs to review the docket. The rule is also available for inspection at the Office of Chief Counsel, DHS/FEMA, 500 C Street, SW., Room 835, Washington, DC 20472–3100.

FOR FURTHER INFORMATION CONTACT: Edward L. Connor, Acting Federal Insurance Administrator, DHS/FEMA, 1800 South Bell Street, Arlington, VA 20598–3010, (202) 646–3429 (Phone), (202) 646–7970 (facsimile), or *Edward.Connor@dhs.gov.*

SUPPLEMENTARY INFORMATION:

Discussion of the Rule

The National Flood Insurance Program Claims Appeals Process is in 44 CFR 62.20. Under 44 CFR 62.20(e)(1), National Flood Insurance Program (NFIP) policyholders currently must submit written appeals of decisions to: Federal Emergency Management Agency, Federal Insurance Administrator, Mitigation Division, 500 C Street, SW., Washington, DC 20472. FEMA has instituted a new mail service that resulted in a change to the address where NFIP policyholders should submit written claims appeals. Under this rule, NFIP policyholders must submit written claims appeals to: DHS/FEMA, Mitigation Directorate, Federal Insurance Administrator, 1800 South Bell Street, Arlington, VA 20598–MS3010. This final rule revises 44 CFR 62.20(e)(1) to reflect the new address. During the transition, any claims appeals received by FEMA at its Washington, DC address, will be forwarded to the Arlington, VA address.

Regulatory Analysis

Administrative Procedure Act

FEMA did not publish a notice of proposed rulemaking (NPRM) for this regulation. FEMA finds that this rule is exempt from the Administrative Procedure Act's (5 U.S.C. 553(b)) notice and comment rulemaking requirements because it is purely procedural in nature. This rule merely updates FEMA's regulations to reflect a change in the mailing address. These changes do not confer any substantive rights, benefits or obligations; therefore this rule will have no substantive effect on the public. Under 5 U.S.C. 553(d)(3), FEMA finds that, for the same reasons, this rule is effective immediately upon publication in the **Federal Register**.

Executive Order 12866, Regulatory Planning and Review

This rule is not a ''significant regulatory action'' under section 3(f) of Executive Order 12866, ''Regulatory Planning and Review'' (58 FR 51735, Oct. 4, 1993), accordingly FEMA has not submitted it to the Office of Management and Budget (OMB) for review. As this rule involves a non-substantive change, FEMA expects that it will not impose any costs on the public.

Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601–612) requires that special consideration be given to the effects of proposed regulations on small entities. This rule does not require a Notice of Proposed Rulemaking and, therefore, is exempt from the requirements of the Regulatory Flexibility Act.

Paperwork Reduction Act of 1995

As required by the Paperwork Reduction Act of 1995 (PRA) Public Law 104–13 (44 U.S.C. 3501 *et seq.*), as amended, an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number.

Although this regulatory change will not result in a new collection of information affected by the PRA, the collection of information for the National Flood Insurance Program Claims Appeal Process is approved under OMB Number, 1660–0095. The 30-day notice published on October 23, 2009 at 74 FR 54838. The Expiration Date for 1660–0095 is January 31, 2010.

Executive Order 13132, Federalism

A rule has implications for federalism under Executive Order 13132, ''Federalism'' (64 FR 43255, Aug. 10, 1999), if it has a substantial direct effect on State or local governments and would either preempt State law or impose a substantial direct cost of compliance on them. FEMA has analyzed this rule under that Order and determined that it does not have implications for federalism.

Unfunded Mandates Reform Act of 1995

The Unfunded Mandates Reform Act of 1995 (the Act), Public Law 104–4, 109 Stat. 48 (March 22, 1995) (2 U.S.C. 1501 *et seq.*), requires Federal agencies to assess the effects of their discretionary regulatory actions. In particular, the Act addresses actions that may result in the expenditure by a State, local, or Tribal government, in the aggregate, or by the private sector of $100,000,000 or more in any one year. Therefore, this rule is not an unfunded Federal mandate under the Act.

Executive Order 12630, Taking of Private Property

This rule will not affect a taking of private property or otherwise have taking implications under Executive Order 12630, ''Governmental Actions and Interference with Constitutionally Protected Property Rights'' (53 FR 8859, Mar. 18, 1988).

Executive Order 12898, Environmental Justice

Under Executive Order 12898, as amended ''Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations'' (59 FR 7629, Feb. 16, 1994), FEMA has undertaken to incorporate environmental justice into its policies and programs. Executive Order 12898 requires each Federal agency to conduct its programs, policies, and activities that substantially affect human health or the environment, in a manner that ensures that those programs, policies, and activities do not have the effect of excluding persons from participation in, denying persons the benefit of, or subjecting persons to discrimination because of their race, color, or national origin or income level.

No action that FEMA can anticipate under this rule will have a disproportionately high and adverse human health or environmental effect on any segment of the population.

Accordingly, the requirements of Executive Order 12898 do not apply to this rule.

Executive Order 12988, Civil Justice Reform

This rule meets applicable standards in sections 3(a) and 3(b)(2) of Executive Order 12988, ''Civil Justice Reform'' (61 FR 4729, Feb. 7, 1996), to minimize litigation, eliminate ambiguity, and reduce burden.

Executive Order 13175, Consultation and Coordination With Indian Tribal Governments

This rule does not have Tribal implications under Executive Order 13175, ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, Nov. 9, 2000), because it does not have a substantial direct effect on one or more Indian Tribes, on the relationship between the Federal Government and Indian Tribes, or on the distribution of power and responsibilities between the Federal Government and Indian Tribes.

National Environmental Policy Act

This rule makes administrative technical changes to FEMA's regulations to reflect changes in agency organization and authorities. It is not a major agency action, nor will it affect the quality of the environment. This final rule will not require the preparation of either an environmental assessment or an environmental impact statement as defined by the National Environmental Policy Act of 1969, Public Law 91–190, 83 Stat. 852 (January 1, 1970)(42 U.S.C. 4321 *et seq.*), as amended.

Congressional Review of Agency Rulemaking

FEMA has sent this final rule to the Congress and to the Government Accountability Office under the Congressional Review of Agency Rulemaking Act (Act), Public Law 104–121, 110 Stat. 873 (March 29, 1996)(5 U.S.C. 804). The rule in not a ''major rule'' within the meaning of that Act and will not result in an annual effect on the economy of $100,000,000 or more. Moreover, it will not result in a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions. FEMA does not expect that it will have ''significant adverse effects'' on competition, employment, investment, productivity, innovation, or on the ability of United States-based enterprises to compete with foreign-based enterprises.

List of Subjects in 44 CFR Part 62

Claims, Flood insurance, Reporting and recordkeeping requirements.

■ For the reasons stated in the preamble, FEMA amends 44 CFR chapter I as follows:

PART 62—SALE OF INSURANCE AND ADJUSTMENT OF CLAIMS

■ 1. The authority citation for part 62 continues to read as follows:

Authority: 42 U.S.C. 4001 *et seq.;* Reorganization Plan No. 3 of 1978, 43 FR 41943, 3 CFR, 1978 Comp., p. 329; E.O. 12127 of Mar. 31, 1979, 44 FR 19367, 3 CFR, 1979 Comp., p. 376.

■ 2. In § 62.20 revise the second sentence of paragraph (e)(1) to read as follows:

§ 62.20 Claims appeals.

* * * * *

(e) * * *

(1) * * * The appeal should be sent to: DHS/FEMA, Mitigation Directorate, Federal Insurance Administrator, 1800 South Bell Street, Arlington, VA 20598–MS3010;

* * * * *

Dated: October 26, 2009.

W. Craig Fugate,

Administrator, Federal Emergency Management Agency.

[FR Doc. E9–26191 Filed 10–29–09; 8:45 am]

BILLING CODE 9110–11–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Office of the Secretary

45 CFR Part 160

RIN 0991–AB55

HIPAA Administrative Simplification: Enforcement

AGENCY: Office of the Secretary, HHS.

ACTION: Interim final rule; request for comments

SUMMARY: The Secretary of the Department of Health and Human Services (HHS) adopts this interim final rule to conform the enforcement regulations promulgated under the Health Insurance Portability and Accountability Act of 1996 (HIPAA) to the effective statutory revisions made pursuant to the Health Information Technology for Economic and Clinical Health Act (the HITECH Act), which was enacted as part of the American Recovery and Reinvestment Act of 2009 (ARRA). More specifically, this interim final rule amends HIPAA's enforcement regulations, as they relate to the imposition of civil money penalties, to incorporate the HITECH Act's categories of violations, tiered ranges of civil money penalty amounts, and revised limitations on the Secretary's authority to impose civil money penalties for established violations of HIPAA's Administrative Simplification rules (HIPAA rules). This interim final rule does not make amendments with respect to those enforcement provisions of the HITECH Act that are not yet effective under the applicable statutory provisions. Such amendments will be subject to forthcoming rulemaking(s).

DATES: *Effective Date:* This interim final rule is effective November 30, 2009. *Comment Date:* Comments on this interim final rule will be considered if received at the appropriate address, as provided below, no later than December 29, 2009.

ADDRESSES: Please submit comments to any one of the addresses specified below:

- *Federal eRulemaking Portal:* You may submit electronic comments at *http://www.regulations.gov.*
- *Regular, Express, or Overnight Mail:* You may mail written comments to the following address only: U.S. Department of Health and Human Services, Office for Civil Rights, Attention: HIPAA Enforcement Rule IFR (RIN 0991–AB55), Hubert H. Humphrey Building, Room 509F, 200 Independence Avenue, SW., Washington, DC 20201.
- *Hand Delivery or Courier:* If you prefer, you may deliver (by hand or courier) your written comments to the following address only: Office for Civil Rights, Attention: HIPAA Enforcement Rule IFR (RIN 0991–AB55), Hubert H. Humphrey Building, Room 509F, 200 Independence Avenue, SW., Washington, DC 20201.

FOR FURTHER INFORMATION CONTACT: Andra Wicks, 202–205–2292.

SUPPLEMENTARY INFORMATION:

I. Public Participation

A. Instructions for Submission of Public Comments

Please follow these instructions when submitting public comments. Please use only one of these methods.

- *Federal eRulemaking Portal:* Follow the instructions for submitting electronic comments at *http://www.regulations.gov.* Attachments will be accepted in Microsoft Word, WordPerfect, or Excel format, though Microsoft Word format is preferred.
- *Regular, Express, or Overnight Mail:* Submit one original and two copies of mailed, written comments. Please allow

sufficient time for timely receipt of mailed comments, as delivery may be subject to delay due to security procedures.

- *Hand Delivery or Courier:* Submit one original and two copies if delivering written comments by hand or by courier. Because access to the interior of the Hubert H. Humphrey Building is not readily available to persons without federal government identification, commenters are encouraged to leave their comments in the mail drop slots located in the main lobby of the building.

B. Inspection of Public Comments

All comments received before the close of the comment period will be available for public inspection, including any personally identifiable or confidential business information contained within each comment. We will post all comments received before the close of the comment period at *http://www.regulations.gov*.

II. Background

This interim final rule amends the sections within 45 CFR part 160 that relate to the authority of the Secretary of the HHS (the Secretary) to impose civil money penalties on entities that violate the HIPAA rules adopted under subtitle F of title II of HIPAA. The interim final rule amends subpart D of part 160 to conform its language to the revisions that became effective on February 18, 2009, under section 1176 of the Social Security Act (the Act), 42 U.S.C. 1320d–5, which was revised pursuant to section 13410(d) of the HITECH Act, Public Law 111–5, 123 Stat. 115, and correspondingly amends the ''Statutory basis and purpose'' section in subpart A. HHS issues these amendments as an interim final rule with request for comments to immediately provide regulated entities with additional notice as to how the Secretary's civil money penalty authority has been strengthened by the HITECH Act and to explain HHS' implementation of such authority with respect to violations occurring on or after February 18, 2009. HHS also pursues this expedited rulemaking to avoid any public misunderstanding or undue delay with respect to implementing Congress' intent to strengthen enforcement of the HIPAA rules.

We set out below the statutory and regulatory background for this interim final rule and follow with a description of our approach to this rulemaking. We then discuss each section of the interim final rule, request comments from the public, and conclude with our analyses of impact and other issues considered under applicable law.

A. Statutory Background

HIPAA Prior to the HITECH ACT

Subtitle F of title II of HIPAA, entitled ''Administrative Simplification,'' was enacted in 1996, for the purpose of improving the Medicare program under title XVIII of the Act, the Medicaid program under title XIX of the Act, and the efficiency and effectiveness of the health care system by encouraging the development of a health information system through the establishment of standards and requirements for the electronic transmission of certain health information. 42 U.S.C. 1320d note. To this end, subtitle F directs the Secretary to adopt national standards (HIPAA standards) for certain information-related activities and to protect the privacy and security of such information.

Under section 1172(a) of the Act, 42 U.S.C. 1320d–1(a), the HIPAA provisions apply to the following persons:

(1) A health plan.

(2) A health care clearinghouse.

(3) A health care provider who transmits any health information in electronic form in connection with a transaction referred to in section 1173(a)(1).

Under sections 1176 and 1177 of the Act, 42 U.S.C. 1320d–5 and 6, these persons or organizations, collectively referred to as ''covered entities,'' may be subject to civil money penalties and criminal penalties for violations of the HIPAA rules. HHS enforces the civil money penalties under section 1176 of the Act, and the U.S. Department of Justice enforces the criminal penalties under section 1177 of the Act.

Prior to the HITECH Act, section 1176(a) of the Act, 42 U.S.C. 1320d–5(a), authorized the Secretary to impose a civil money penalty, as follows:

(1) IN GENERAL. Except as provided in subsection (b), the Secretary shall impose on any person who violates a provision of this part [42 U.S.C. 1320d *et seq.*] a penalty of not more than $100 for each such violation, except that the total amount imposed on the person for all violations of an identical requirement or prohibition during a calendar year may not exceed $25,000.

(2) PROCEDURES. The provisions of section 1128A [42 U.S.C. 1320a–7a] (other than subsections (a) and (b) and the second sentence of subsection (f)) shall apply to the imposition of a civil money penalty under this subsection in the same manner as such provisions apply to the imposition of a penalty under such section 1128A.

Prior to the HITECH Act, section 1176(b) of the Act, 42 U.S.C. 1320d–5(b), set out limitations on the Secretary's above referenced authority to impose civil money penalties. Such limitations included prohibitions on imposing civil money penalties for: (1) An act that ''constitutes an offense punishable under section 1177'' of the Act (the criminal penalty provisions), (2) violations ''if it is established to the satisfaction of the Secretary that the person liable for the penalty did not know, and by exercising reasonable diligence would not have known, that such person violated the provision,'' and (3) violations if the failure to comply was due ''to reasonable cause and not to willful neglect'' and was corrected during a 30-day time period or pursuant to an extension determined to be appropriate by the Secretary based on the nature and circumstances of the covered entity's failure to comply.

Section 13410(d) of the HITECH Act

The HITECH Act was incorporated into ARRA to promote the adoption and meaningful use of health information technology. Subtitle D of the HITECH Act, sections 13400–13424, addresses the privacy and security concerns associated with the electronic transmission of health information. It does so, in part, through several provisions that strengthen the civil and criminal enforcement of the HIPAA rules. Many of these enforcement provisions became effective as of February 18, 2009 and are the impetus of this rulemaking. Other enforcement provisions have yet to become effective under the HITECH Act and are therefore subject to future rulemaking.

Section 13410(d) of the HITECH Act became effective February 18, 2009, revising section 1176 of the Act, 42 U.S.C. 1320d–5, to strengthen enforcement of the HIPAA rules in several ways. As modified, section 1176(a) establishes categories of violations that reflect increasing levels of culpability, requires that a penalty determination be based on the nature and extent of the violation and the nature and extent of the harm resulting from the violation, and establishes tiers of increasing penalty amounts that establish, by reference, the range of the Secretary's authority to impose civil money penalties. The revised text of section 1176(a) that became effective February 18, 2009, pursuant to section 13410(d) of the HITECH Act is as follows:

GENERAL PENALTY.

(1) IN GENERAL. Except as provided in subsection (b), the Secretary shall impose on any person who violates a provision of this part—

(A) in the case of a violation of such provision in which it is established that the person did not know (and by exercising reasonable diligence would not have known) that such person violated such provision, a penalty for each such violation of an amount that is at least the amount described in paragraph (3)(A) but not to exceed the amount described in paragraph (3)(D);

(B) in the case of a violation of such provision in which it is established that the violation was due to reasonable cause and not to willful neglect, a penalty for each such violation of an amount that is at least the amount described in paragraph (3)(B) but not to exceed the amount described in paragraph (3)(D); and

(C) in the case of a violation of such provision in which it is established that the violation was due to willful neglect—

(i) if the violation is corrected as described in subsection (b)(3)(A),[1] a penalty in an amount that is at least the amount described in paragraph (3)(C) but not to exceed the amount described in paragraph (3)(D); and

(ii) if the violation is not corrected as described in such subsection, a penalty in an amount that is at least the amount described in paragraph (3)(D).

In determining the amount of a penalty under this section for a violation, the Secretary shall base such determination on the nature and extent of the violation and the nature and extent of the harm resulting from such violation.

(2) PROCEDURES. The provisions of section 1128A (other than subsections (a) and (b) and the second sentence of subsection (f)) shall apply to the imposition of a civil money penalty under this subsection in the same manner as such provisions apply to the imposition of a penalty under such section 1128A.

(3) Tiers of penalties described.—For purposes of paragraph (1), with respect to a violation by a person of a provision of this part—

(A) the amount described in this subparagraph is $100 for each such violation, except that the total amount imposed on the person for all such violations of an identical requirement or prohibition during a calendar year may not exceed $25,000;

(B) the amount described in this subparagraph is $1,000 for each such violation, except that the total amount imposed on the person for all such violations of an identical requirement or prohibition during a calendar year may not exceed $100,000;

(C) the amount described in this subparagraph is $10,000 for each such violation, except that the total amount imposed on the person for all such violations of an identical requirement or prohibition during a calendar year may not exceed $250,000; and

(D) the amount described in this subparagraph is $50,000 for each such violation, except that the total amount imposed on the person for all such violations of an identical requirement or prohibition during a calendar year may not exceed $1,500,000.

Section 13410(d) of the HITECH Act also revised section 1176(b) of the Act by: (1) Striking the affirmative defense for violations in which the covered entity did not know, or by reasonable diligence would not have known, of the violation (such violations are now punishable under the first tier of penalties); and (2) revising the subsection that provides an affirmative defense for a 30-day time period of correction to only require that the covered entity demonstrate the violation was not due to willful neglect (the statute previously also required a showing that the violation was due to reasonable cause). The revised statutory text of section 1176(b) that became effective February 18, 2009,[2] pursuant to section 13410(d) of the HITECH Act is as follows:

LIMITATIONS.

(1) OFFENSES OTHERWISE PUNISHABLE. No penalty may be imposed under subsection (a) and no damages obtained under subsection (d) with respect to an act if the act constitutes an offense punishable under section 1177.

(2) FAILURES DUE TO REASONABLE CAUSE.

(A) IN GENERAL. Except as provided in subparagraph (B) or subsection (a)(1)(C), no penalty may be imposed under subsection (a) and no damages obtained under subsection (d) if the failure to comply is corrected during the 30-day period beginning on the first date the person liable for the penalty knew, or by exercising reasonable diligence would have known, that the failure to comply occurred.

(B) EXTENSION OF PERIOD.—

(i) NO PENALTY.—With respect to the imposition of a penalty by the Secretary under subsection (a), the period referred to in subparagraph (A) may be extended as determined appropriate by the Secretary based on the nature and extent of the failure to comply.

(ii) ASSISTANCE.—If the Secretary determines that a person failed to comply because the person was unable to comply, the Secretary may provide technical assistance to the person during the period described in subparagraph (A). Such assistance shall be provided in any manner determined appropriate by the Secretary.

(3) REDUCTION.—In the case of a failure to comply which is due to reasonable cause and not to willful neglect, any penalty under subsection (a) and any damages under subsection (d) that is not entirely waived under paragraph (3)[3] may be waived to the extent that the payment of such penalty would be excessive relative to the compliance failure involved.

B. Regulatory Background

Section 1173 of the Act, 42 U.S.C. 1320d–2, and section 264 of HIPAA, require the Secretary to adopt a number of national standards to facilitate the exchange of certain health information and to protect the privacy and security of such information. The Secretary has adopted a number of national standards to that end, which include the following: Standards for Electronic Transactions and Code Sets (Transactions and Code Sets Rules); Standards for Privacy of Individually Identifiable Health Information (HIPAA Privacy Rule); Standard Unique Employer Identifier (EIN Rule); Security Standards (HIPAA Security Rule); and Standard Unique Health Identifier for Health Care Providers (NPI Rule). *See* 70 FR 20224, 20225–26 (April 18, 2005) for a more detailed description of the history of these HIPAA rules. Covered entities are required to comply with these HIPAA standards.

In addition, the Secretary promulgated rules that relate to compliance with, and enforcement of, the HIPAA rules, which are codified at 45 CFR part 160, subparts C, D, and E and collectively referred to as the Enforcement Rule. The Secretary first issued an interim final rule promulgating the procedural requirements for imposition of civil money penalties on violations of the privacy standards on April 17, 2003, Civil Money Penalties: Procedures for Investigations, Imposition of Penalties (68 FR 18896). The Secretary subsequently proposed a rule on April 18, 2005, HIPAA Administrative Simplification: Enforcement; Proposed Rule (70 FR 20224), proposing the amendment of 45 CFR part 160, subparts A (General Provisions), C (Compliance and Enforcement), and E (Procedures for Hearing), proposing a new subpart D (Imposition of Civil Money Penalties) that addressed the substantive issues related to the imposition of civil money penalties, and proposing that the above provisions be applied to all of the HIPAA rules, rather

[1] We note that, as amended, section 1176 no longer includes a subsection (b)(3)(A). We interpret this text as referencing the 30-day period in section 1176(b)(2)(A), which was designated as section 1176(b)(3)(A) prior to the HITECH Act's amendment. We request public comment on this interpretation, to the extent there is disagreement.

[2] Note that section 13410(a) of the HITECH Act further amends section 1176(b) of the Act with respect to penalties imposed on or after February 18, 2011. These changes are not reflected in the statutory text, as they have yet to become effective.

[3] We note that this reference to paragraph (3) creates a circular reference which appears to be an error. Section 13410(d) of the HITECH Act redesignated the prior paragraph (3) to paragraph (2), but did not include a conforming revision to this reference. Accordingly, we interpret this reference as being to paragraph (2) (i.e., the affirmative defense for violations that are not due to willful neglect and are timely corrected) and request public comment to the extent there is disagreement.

than only the privacy standards. The Secretary then adopted a final rule, HIPAA Administrative Simplification: Enforcement; Final Rule (71 FR 8390, February 16, 2006). The preambles of these rulemakings provide additional information that may be helpful to readers seeking a general understanding of HIPAA's compliance and enforcement scheme. Where, if at all, language in these prior preambles is contrary to language in this preamble or regulation text, the language herein applies.

Subpart D of the Enforcement Rule pertains to the imposition of civil money penalties under section 1176 of the Act and includes a number of provisions that apply to violations occurring before section 13410(d) of the HITECH Act's effective date of February 18, 2009, but that conflict with the statutory language as it has been revised with respect to violations occurring on or after February 18, 2009. Thus, the primary objectives of this interim final rule are to conform the Enforcement Rule provisions found in subpart D to the amended language in section 1176 of the Act, to provide covered entities with additional notice of the Secretary's revised statutory authority with respect to the imposition of civil money penalties, and to avoid any public misunderstanding or undue delay with respect to Congress' intent to strengthen enforcement of the HIPAA rules.

III. Approach to the Interim Final Rule

As stated previously, this interim final rule amends several provisions of the Enforcement Rule, subpart D, to conform its language regarding HHS' imposition of civil money penalties to section 1176 of the Act, which section 13410(d) of the HITECH Act revised as of February 18, 2009. Subtitle D of the HITECH Act, which specifically pertains to privacy, contains several other provisions crafted to strengthen enforcement, some but not all of which pertain to HHS' implementation of the Enforcement Rule. We recognize that additional amendments will become necessary as such provisions become effective, but we do not adopt amendments in this interim final rule pursuant to those other provisions of subtitle D which have not yet become statutorily effective and have not, as a result, yet operated to revise HHS' enforcement authority under section 1176 of the Act.

HHS has concluded that it has good cause, under 5 U.S.C. 553(b)(B), to waive the notice-and-comment requirements of the Administrative Procedure Act (APA) and to proceed with this interim final rule. We first note that section 13410(d) of the HITECH Act's amendment of section 1176 of the Act, 42, U.S.C. 1320d–5, became effective the day after the date of enactment and that many covered entities may be unaware they are currently subject to significantly greater penalties for violations of the HIPAA rules. In addition, section 13410(d) of the HITECH Act's amendments have caused a number of provisions of the Enforcement Rule to conflict with the amended statute, and the resulting inconsistency has led to public confusion, both as to the penalty amounts for violations of the HIPAA rules and as to what defenses remain in effect. Delaying the promulgation of these conforming amendments would also forestall HHS' timely implementation of the strengthened enforcement approach mandated by statute and would maintain the status quo with respect to the heightened privacy and security concerns associated with the electronic transmission of health information among health care entities.

Based on the above reasons, we believe that delaying amendment to the Enforcement Rule, through the exercise of notice-and-comment rulemaking prior to publication of a final rule, would be impracticable, unnecessary, or contrary to public policy. Accordingly, HHS has good cause under the APA, 5 U.S.C. 553(b)(B), to waive notice-and-comment rulemaking and to proceed directly with the issuance of a final rule. At the same time, HHS is interested in the public's input and requests public comments regarding the substance of these amendments.

While HIPAA generally requires certain consultations with industry as a predicate to the issuance of the HIPAA standards, this interim final rule does not adopt standards, as the term is defined and interpreted under subtitle F of title II of HIPAA. Therefore, the requirement for such industry consultations in section 1172(c) of the Act, 42 U.S.C. 1320d–1(c), does not apply. For the same reason, the timeframes for compliance with the HIPAA rules, as set forth in section 1175 of the Act, 42 U.S.C. 1320d–4, do not apply.

IV. Provisions in the Interim Final Rule

This interim final rule amends 45 CFR part 160, subpart D, which establishes rules relating to the imposition of civil money penalties, to conform several provisions to section 13410(d) of the HITECH Act's amendments to section 1176 of the Act, 42 U.S.C. 1320d–6, which became effective February 18, 2009. This interim final rule's amendments distinguish between violations occurring before February 18, 2009, and violations occurring on or after that date, with respect to the potential amount of the civil money penalty and the affirmative defenses available to covered entities. We discuss this interim final rule's amendments to the Enforcement Rule on a provision-by-provision basis below:

A. Subpart A—General Provisions

1. Section 160.101—Statutory Basis and Purpose

Section 160.101 is amended to add the statutory citation for section 13410(d) of the HITECH Act to the list of the statutes that the requirements of the subchapter are designed to implement.

B. Subpart D—Imposition of Civil Money Penalties

1. Section 160.401—Definitions

Section 160.401 is added and defines the terms of *reasonable cause, reasonable diligence* and *willful neglect,* using the same definitions currently found at § 160.410. As discussed below, we are removing these terms from § 160.410 as a conforming amendment. This reorganization of the definitions signals the application of these terms to the entirety of subpart D. We do not discuss the terms further, as we are amending their placement in the rule but not their substance. Readers who would like a better understanding of these terms are encouraged to consult prior preamble explanations at 70 FR 20224, 20237–9 (April 18, 2005) and 71 FR 8390, 8409–11 (February 16, 2006).

2. Section 160.404—Amount of Civil Money Penalties

Subsection 160.404(b) is amended to revise the range of potential civil money penalty amounts a covered entity will be subject to based on the HITECH Act's amendments of section 1176 of the Act, 42 U.S.C. 1320–5, which are currently in effect. As amended, § 160.404(b)(1) retains the range of penalty amounts enumerated prior to the statutory revision for those violations occurring before February 18, 2009. The current content of § 160.404(b)(2) is re-designated as § 160.404(b)(3). A new § 160.404(b)(2) is added which identifies the range of penalty amounts for violations occurring on or after February 18, 2009.

Section 160.404 currently implements a penalty scheme, as required by section 1176(a)(1) prior to the HITECH Act's revisions, which explicitly established the maximum penalty amount for each violation as ''not more than $100'' and the maximum penalty amount ''for all violations of an identical requirement or prohibition during a calendar year'' as ''not to exceed $25,000.'' Subsection 160.404(b)(1) retains this penalty scheme for violations occurring before February 18, 2009, though its language is slightly modified to accommodate the parallel provisions for those violations that occur on or after February 18, 2009.

As modified, section 1176(a)(1) generally establishes a minimum penalty amount ''for each such violation'' by stating the penalty amount is to be ''at least'' the amount described in a specifically referenced tier and establishes a maximum penalty amount per violation by stating that each such violation is ''not to exceed the amount described in [section 1176(a)(3)(D)].'' [4] Each referenced penalty tier additionally provides a total penalty amount for all such violations of an identical requirement or prohibition during a calendar year. The HITECH Act's revised penalty scheme is similar to its predecessor with respect to its identification of a range of available civil money penalty amounts, a maximum penalty amount for violations of identical provisions during a calendar year, and generally with respect to the discretion it allows HHS in determining the appropriate penalty amount within the range prescribed.

The revised penalty scheme differs significantly from its predecessor by its establishment of several categories of violations that reflect increasing levels of culpability. The revised penalty scheme also differs significantly from its predecessor in its establishment of the range of available penalty amounts for each category of violation by reference to tiers of penalty amounts. Each tier specifies a minimum penalty amount that accompanies the increasing culpability associated with each category of violation and, for three of the four violation categories, defaults to ''the amount described in paragraph 3(D)'' as the outside limit.

For example, in the case of a violation where it is established that a covered entity did not know of the violation and would not have known through the exercise of reasonable diligence, section 13410(d) of the HITECH Act provides that the minimum penalty amount for each such violation is ''at least'' the amount described in paragraph (3)(A) [section 1176(a)(3)(A)] (i.e., $100) but is ''not to exceed'' the amount described in paragraph (3)(D) [section 1176(a)(3)(D)] (i.e., $50,000). Paragraphs 1176(a)(3)(A) and (D) each additionally provide that the total penalty amount for multiple violations of an identical requirement or prohibition during a calendar year is $25,000 and $1.5 million respectively.

HHS considered the conflicting statutory language that references two tiers of penalties ''for each violation,'' which each provide a penalty amount ''for all such violations'' of an identical requirement or prohibition in a calendar year. With the exception of violations due to willful neglect that are not timely corrected, this interim final rule adopts a range of penalty amounts between the minimum given in one tier and the maximum given in the second tier for each violation and adopts the amount of $1.5 million as the limit for all violations of an identical provision of the HIPAA rules. For violations due to willful neglect that are not timely corrected, this interim final rule adopts the penalty amount of $50,000 as the minimum for each violation and $1.5 million for all such violations of an identical requirement or prohibition. These regulatory amendments are consistent with the most logical reading of section 1176(a)(1) and (3). The amendments are also consistent with Congress' intent to strengthen enforcement, in part, by increasing the minimum penalty amounts available according to categories of violation, and with the clear discretion Congress has provided to impose a penalty amount up to the amount described in ''paragraph (3)(D).''

More specifically, HHS amends § 160.404(b)(2) to reflect each category of violation that will serve as the basis for a civil money penalty on or after February 18, 2009, as well as the respective range of penalty amounts available. The range of penalty amounts available for the first three categories of violations (i.e., where it is established the covered entity did not reasonably know of the violation, the violation was due to a reasonable cause, or the violation was due to willful neglect but timely corrected) is defined consistent with the controlling language of section 1176(a)(1)(A)–(C)(i), whereby the minimum penalty amount for each violation is set pursuant to the specific tier referenced by each category of violation, and the maximum penalty amount for each violation is capped at $50,000, the amount identified ''for such each violation'' in section 1176(a)(3)(D). For these categories of violations, the maximum penalty amount available for all such violations of an identical provision in a calendar year is consistently capped at $1.5 million, the other amount referenced in section 1176(a)(1) as that ''not to exceed'' and identified in section 1176(a)(3)(D) ''for all such violations of an identical requirement or prohibition during a calendar year.''

The penalty amounts available for the fourth level of culpability (i.e., where it is established the violation is due to willful neglect but not timely corrected) are also consistent with the controlling language of section 1176(a)(1)(C)(ii). Unlike the other levels of culpability at section 1176(a)(1)(A), (B) and (C)(i), section 1176(a)(1)(C)(ii) only provides in its reference to section 1176(a)(3)(D) a minimum penalty amount of $50,000 ''for each violation'' and a penalty cap of $1.5 million for multiple violations of an identical requirement or prohibition in a calendar year.

We highlight the penalty amounts in Table 1, below, to ensure that covered entities are fully aware of their potential liability:

TABLE 1—CATEGORIES OF VIOLATIONS AND RESPECTIVE PENALTY AMOUNTS AVAILABLE

Violation category—Section 1176(a)(1)	Each violation	All such violations of an identical provision in a calendar year
(A) Did Not Know	$100–$50,000	$1,500,000
(B) Reasonable Cause	1,000–50,000	1,500,000
(C)(i) Willful Neglect—Corrected	10,000–50,000	1,500,000
(C)(ii) Willful Neglect—Not Corrected	50,000	1,500,000

[4] Section 1176(a)(1) notably provides no maximum penalty amount, however, with respect to ''each such violation'' described in subparagraph (C)(ii) (for violations established as due to willful neglect and not timely corrected), although a cap is set by section 1176(a)(3)(D). This caveat is discussed further below.

We note that HHS will not impose the maximum penalty amount in all cases. Rather, HHS will determine penalty amounts as required by the statute at section 1176(a)(1) and the regulations at § 160.408. That is, penalty determinations will be based on the nature and extent of the violation, the nature and extent of the resulting harm, as well as the other factors set forth at § 160.408 (such as the covered entity's history of prior compliance or financial condition).

For counting violations that occur on or after February 18, 2009, HHS will continue to utilize the methodology discussed in prior preambles of the Enforcement Rule. See 70 FR 20224, 20233–35 (April 18, 2005) and 71 FR 8390, 8404–07 (February 16, 2006). For violations that began prior to February 18, 2009, and continue after that date, we will treat violations occurring before February 18, 2009, as subject to the penalties in effect prior to February 18, 2009 and violations occurring on or after February 18, 2009, as subject to the penalties in effect on or after February 18, 2009.

3. Section 160.410—Affirmative Defenses

As previously discussed, the terms *reasonable cause, reasonable diligence* and *willful neglect,* have been moved from § 160.410 to § 160.401 in order to apply more generally to all of subpart D. Accordingly, we have removed the current paragraph (a) from § 160.410 and redesignated paragraph (b) as paragraph (a).

We also amended § 160.410 to conform its provisions to the statutory language in section 1176(a)(3), as revised by section 13410(d) of the HITECH Act. Section 160.410(b) currently provides three affirmative defenses to the Secretary's authority to impose a civil money penalty, including the following:

(1) The violation is an act punishable under 42 U.S.C. 1320d–6;

(2) The covered entity establishes, to the satisfaction of the Secretary, that it did not have knowledge of the violation, determined in accordance with the federal common law of agency, and by exercising reasonable diligence, would not have known that the violation occurred; or

(3) The violation is—

(i) Due to reasonable cause and not willful neglect; and

(ii) Corrected during either:

(A) The 30-day period beginning on the date the covered entity liable for the penalty knew, or by exercising reasonable diligence would have known, that the violation occurred; or

(B) Such additional period as the Secretary determines to be appropriate based on the nature and extent of the failure to comply

Section 13410(d) of the HITECH Act revises section 1176(b) of the Act to: (a) Strike the limitation on imposing a penalty when a covered entity establishes, to the Secretary's satisfaction, that it ''did not know, and by exercising reasonable diligence would not have known'' of the violation; and (b) extend the affirmative defense for violations that are timely corrected, which was previously limited to violations due to ''reasonable cause and not to willful neglect,'' to all violations not due to willful neglect.

The amendments conform § 160.410 to distinguish the limitations placed on the Secretary's authority to impose civil money penalties before and after the HITECH Act by: (a) Revising the current provisions, which have been redesignated as paragraph (a), to apply only ''[f]or violations occurring prior to February 18, 2009''; and (b) adding a new paragraph (b) that applies ''[f]or violations occurring on or after February 18, 2009.'' The amendments also conform § 160.410 to the amended section 1176(b) by removing a covered entity's lack of knowledge as an affirmative defense for violations occurring on or after February 18, 2009. As a result, a covered entity that did not know and reasonably should not have known of such violations, will not have this affirmative defense available, unless it also corrects the violation during the 30-day time period beginning on the first date of such knowledge or during the period determined appropriate by the Secretary based on the nature and extent of the failure to comply. The amendments likewise revise the affirmative defenses available for violations occurring on or after February 18, 2009 to conform to the amended statute by removing any specific reference to ''reasonable cause'' while retaining more generalized language applicable to all violations ''not due to willful neglect.'' Notwithstanding these revisions, the Secretary may continue to use discretion in providing technical assistance, obtaining corrective action, and resolving possible noncompliance by informal means where the possible noncompliance is due to reasonable cause or in the event a person did not reasonably know that the violation occurred.

We note that the amendments made to § 160.410 do not alter the beginning of the 30-day cure period. Section 1176(b)(2)(A) of the Act continues to provide that the 30-day cure period begins ''on the first date the person liable for the penalty knew, or by exercising reasonable diligence would have known, that the failure to comply occurred.'' As prior preambles to the Enforcement Rule explain, the statute, ''on its face suggests that the knowledge involved must be knowledge that a 'violation' has occurred, not just knowledge of the facts constituting the violation. * * * [HHS], thus, interpret[s] this knowledge requirement to mean that the covered entity must have knowledge that a violation has occurred, not just knowledge of the facts underlying the violation.'' However, the ''reasonable diligence'' requirement makes the affirmative defense unavailable, in the event a covered entity's ''lack of knowledge'' resulted from its failure to inform itself about its compliance obligations or to investigate received complaints or other information indicating likely noncompliance. See 70 FR 20224, 20237–8 (April 18, 2005) and 71 FR 8390, 8410 (February 16, 2006). Thus, HHS expects its determination of the beginning of the cure period will be based on evidence gathered during its investigation of when a covered entity had actual or constructive knowledge of a violation.

We also note that the amendments made to § 160.410 do not alter affirmative defenses with respect to violations due to willful neglect. Section 1176(b)(2)(A) still operates to exclude violations due to willful neglect from those that, if timely corrected, would be exempt from the imposition of a civil money penalty. Violations due to willful neglect are therefore not eligible for extension, nor will their timely correction be an affirmative defense. Timely correction will, however, determine which tier of penalty amounts will be applicable to violations due to willful neglect.

Thus, for example, referring to ''Table 1. Categories of Violations and Respective Penalty Amounts Available,'' which appears in the discussion about § 160.404, a covered entity's timely correction would bar the Secretary's imposition of the penalty amounts identified in columns two and three, if the covered entity did not reasonably know of the violation or if the violation was due to reasonable cause. In contrast, a covered entity's timely correction of a violation due to willful neglect would not be an affirmative defense that bars the Secretary's imposition of a penalty amount identified in columns two and three of the table.

To determine the appropriate penalty tier for a violation due to willful neglect, HHS will calculate the 30-day cure period in the same manner as that described above for the affirmative defense of timely correction of a violation not due to willful neglect. Our determination of when a covered entity first had actual or constructive knowledge of a violation due to willful neglect for the purpose of calculating whether it was timely corrected will be based on evidence gathered during our investigation and will thus necessarily be made on a case-by-case basis. The minimum penalty amount under the HITECH Act for a violation due to willful neglect that is corrected during the 30-day cure period is significantly less than the minimum penalty amount for a violation due to willful neglect that is not timely corrected. In recognition of the HITECH Act's enhanced penalties and its application of a 30-day cure period to a determination of the appropriate penalty tier for a violation due to willful neglect, we request public comment on whether there are alternative approaches to calculating the beginning of the 30-day cure period for this purpose.

This interim final rule does not amend § 160.410 with respect to the affirmative defense pertaining to criminal violations, punishable under 42 U.S.C. 1320d–6, since the relevant statutory revision will not become effective until February 18, 2011. The interim final rule also does not amend § 160.410 with respect to the enforcement authority of state attorneys general to bring civil actions under the HIPAA rules in certain circumstances, as set forth in § 13410(e) of the HITECH Act, since such authority operates pursuant to the statute and does not require HHS rulemaking.

4. Section 160.412—Waiver

Section 160.412 is amended to reflect the revisions to § 160.410. Regardless of whether violations occur before, on, or after February 18, 2009, the Secretary may continue to provide a waiver for violations due to reasonable cause and not willful neglect that are not timely corrected (pursuant to the correction period in revised § 160.410(a)(3)(ii) or (b)(2)(ii), as applicable).

5. Section 160.420—Notice of Proposed Determination

Section 160.420(a)(4) is amended to add the requirement that, in addition to the proposed penalty amount, HHS identify the applicable violation category in § 160.404 upon which the proposed penalty amount is based. While such additional language is not required by statute, HHS makes this amendment to provide covered entities with additional notice and information to benefit their understanding of the violation findings in the Notice of Proposed Determination.

V. Request for Comments

HHS seeks public comments on any aspect of this interim final rule. In particular, we invite public comments with respect to the following: (1) The calculation of when the 30-day cure period begins for the purpose of determining the appropriate penalty tier for a violation due to willful neglect as discussed above in the penultimate paragraph of Section IV.B.3; (2) whether moving the definitions of ''reasonable cause,'' ''reasonable diligence,'' and ''willful neglect'' to the new § 160.401 leads to any unintended consequences; and (3) the HHS interpretations of Congressional intent referenced in footnotes 1 and 3.

VI. Impact Statement and Other Required Analyses

A. Paperwork Reduction Act

We reviewed this interim final rule to determine whether it invokes issues that would relate to the Paperwork Reduction Act (PRA). While the PRA applies to agencies and collections of information conducted or sponsored by those agencies, 5 CFR 1320.4(a) exempts collections of information that occur ''during the conduct of * * * an administrative action, investigation, or audit involving an agency against specific individuals or entities,'' except for investigations or audits ''undertaken with reference to a category of individuals entities or entities such as a class of licensees or an entire industry.'' The rules adopted below come squarely within this exemption, as they deal entirely with administrative investigations and actions against specific individuals or entities. Therefore, we have determined that the PRA does not apply to this interim final rule and need not be reviewed by the Office of Management and Budget under the authority of the PRA.

B. Executive Order 12866

We also reviewed the impacts of this interim final rule as required by Executive Order 12866 (58 FR 51735, October 4, 1993), which directs agencies to assess all costs and benefits of available regulatory alternatives and, if regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety effects, distributive impacts, and equity). Executive Order 12866 requires that a regulatory impact analysis (RIA) be prepared for ''significant regulatory actions,'' which it defines at section 3(f), to include rules 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 government 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 the Executive Order.

Executive Order 12866 requires a full economic impact analysis only for ''economically significant'' rules under section 3(f)(1). The amendments contained within this interim final rule only conform the regulatory language of subpart D to that of the Act's revised statutory basis, in a way that differentiates the categories of violations for which a civil money penalty may be imposed, sets forth ranges of increasing penalty amounts with respect to each category of violation, and narrows the grounds for the affirmative defenses available.

HHS has concluded, for reasons similar, and in addition to, those discussed in the preambles to the proposed and final Enforcement Rules at 70 FR 20224, 20248–49 (April 18, 2005) and 71 FR 8390, 8424 (February 16, 2006), that the impact of this interim final rule is not such that it would reach the ''economically significant'' threshold under section 3(f)(1) of the Executive Order. As was the case at the time of earlier promulgations, the costs covered entities may incur with respect to their compliance with the Enforcement Rule, itself, should be low in most cases. That is, covered entities that comply with the HIPAA rules voluntarily, as is expected, should not incur any additional, significant costs with respect to the imposition of a civil money penalty. HHS' experience enforcing the HIPAA rules also suggests that violations should not collectively amount to an annual effect on the economy of $100 million or more, even in light of the higher penalty amounts prescribed by statute.

Further, HHS does not expect the imposition of civil money penalties pursuant to these amendments to ''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 government or communities.'' To the contrary, HHS maintains that the benefits brought by the HIPAA provisions and their strengthened enforcement under this interim final rule will far outweigh the potential costs. We believe the added penalties will encourage covered entities to take steps necessary to comply and thus not be liable for violations. In addition, we believe the conforming amendments made with respect to the affirmative defenses available will encourage covered entities to quickly and voluntarily correct acts or omissions that might otherwise be established as violations of the HIPAA rules. Greater vigilance in protecting privacy may also encourage public trust in the industry's use of health information technology. For these reasons, among others, a detailed cost-benefit assessment of the interim final rule is not required.

C. Other Analyses

We also examined the impacts of the interim final rule as required by the Regulatory Flexibility Act (RFA), section 1102(b) of the Act, the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4), the Small Business Regulatory Enforcement and Fairness Act, 5 U.S.C. 801 *et seq.,* and Executive Order 13132.

The RFA requires agencies to determine whether a rule will have a significant economic impact on a substantial number of small entities. For purposes of the RFA, small entities include small businesses, nonprofit organizations, and government jurisdictions. The standard size of a ''small'' health care entity ranges from $7 million to $34.5 million in revenues in any one year. HHS assumes that the majority of covered entities to which this interim final rule is applicable are likely to be deemed small businesses based on the size standards of the Small Business Administration. As is discussed above, HHS expects that a covered entity's voluntary compliance and timely correction will not result in any significant economic impact, and that only a small percentage of violations occurring on or after February 18, 2009, will necessitate investigation and the imposition of a civil money penalty due to willful neglect. As discussed in prior enforcement rulemakings, (70 FR 20224, 20249 (April 18, 2005) and 71 FR 8390, 8424 (February 16, 2006)), the absence of evidence that small entities have a higher rate of noncompliance than larger entities provides additional support for the Secretary's certification that this rule will not have a significant economic impact on a substantial number of small entities.

Section 1102(b) of the Act requires agencies to prepare a regulatory impact analysis if a rule may have a significant impact on the operations of a substantial number of small rural hospitals. This analysis must conform to the provisions of section 603 (proposed documents)/ 604 (final documents) of the RFA. A small rural hospital, for purposes of section 1102(b) of the Act, is defined as a hospital that is located outside of a Metropolitan Statistical Area and has fewer than 100 beds. For reasons described above, this interim final rule is not expected to have a significant impact on small rural hospitals any more than it is expected to negatively impact any ''small'' health care entity.

Section 202 of the Unfunded Mandates Reform Act of 1995, 2 U.S.C. 1531 *et seq.,* requires that agencies assess anticipated costs and benefits before issuing a rule that may result in an aggregate expenditure of $100 million in any one year, by State, local, or tribal governments, or by the private sector. The Small Business Regulatory Enforcement Act of 1996 (SBREFA), 5 U.S.C. 801 *et seq.,* also requires that rules that will have an impact on the economy of $100 million or more per annum be submitted for Congressional review. For the reasons discussed above, this interim final rule would not impose a burden large enough to require a statement under section 202 of the Unfunded Mandates Reform Act of 1995 or Congressional review under the SBREFA.

Executive Order 13132 establishes certain requirements that an agency must meet when it promulgates a rule that imposes substantial direct requirement costs on State and local governments, preempts State law, or otherwise has Federalism implications. As previously discussed, this interim final rule is not likely to have substantial economic effects. Any preemption of State law that could occur would be a function of the HIPAA statute and the underlying HIPAA rules and not these amendments to the Enforcement Rule, which principally establish the means by which the statutory civil money penalty provisions will be implemented. This interim final rule does 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,'' nor does it have ''Federalism implications.'' It is therefore not subject to Executive Order 13132.

List of Subjects in 45 CFR Part 160

Administrative practice and procedure, Computer technology, Electronic transactions, Employer benefit plan, Health, Health care, Health facilities, Health insurance, Health records, Hospitals, Investigations, Medicaid, Medical research, Medicare, Penalties, Privacy, Reporting and recordkeeping requirements, Security.

■ For the reasons set forth in the preamble, the Department of Health and Human Services amends 45 CFR subtitle A, subchapter C, part 160, as set forth below.

PART 160—GENERAL ADMINISTRATIVE REQUIREMENTS

■ 1. The authority citation for part 160 is revised to read as follows:

Authority: 42 U.S.C. 1302(a), 42 U.S.C. 1320d–1320d–8, sec. 264 of Public Law 104–191, 110 Stat. 2033–2034 (42 U.S.C. 1320d–2 (note)), 5 U.S.C. 552; and secs.13400 and 13402, Public Law 111–5, 123 Stat. 258–263.

* * * * *

■ 2. Revise § 160.101 to read as follows:

§ 160.101 Statutory basis and purpose.

The requirements of this subchapter implement sections 1171 through 1179 of the Social Security Act (the Act), as added by section 262 of Public Law 104–191, section 264 of Public Law 104–191, section 13402 of Public Law 111–5, and section 13410(d) of Public Law 111–5.

■ 3. Add § 160.401 to subpart D to read as follows:

§ 160.401 Definitions.

As used in this subpart, the following terms have the following meanings:

Reasonable cause means circumstances that would make it unreasonable for the covered entity, despite the exercise of ordinary business care and prudence, to comply with the administrative simplification provision violated.

Reasonable diligence means the business care and prudence expected from a person seeking to satisfy a legal requirement under similar circumstances.

Willful neglect means conscious, intentional failure or reckless indifference to the obligation to comply with the administrative simplification provision violated.

■ 4. Revise paragraph (b) of § 160.404 to read as follows:

§ 160.404 Amount of a civil monetary penalty.

* * * * *

(b) The amount of a civil money penalty that may be imposed is subject to the following limitations:

(1) For violations occurring prior to February 18, 2009, the Secretary may not impose a civil money penalty—

(i) In the amount of more than $100 for each violation; or

(ii) In excess of $25,000 for identical violations during a calendar year (January 1 through the following December 31);

(2) For violations occurring on or after February 18, 2009, the Secretary may not impose a civil money penalty—

(i) For a violation in which it is established that the covered entity did not know and, by exercising reasonable diligence, would not have known that the covered entity violated such provision,

(A) In the amount of less than $100 or more than $50,000 for each violation; or

(B) In excess of $1,500,000 for identical violations during a calendar year (January 1 through the following December 31);

(ii) For a violation in which it is established that the violation was due to reasonable cause and not to willful neglect,

(A) In the amount of less than $1,000 or more than $50,000 for each violation; or

(B) In excess of $1,500,000 for identical violations during a calendar year (January 1 through the following December 31);

(iii) For a violation in which it is established that the violation was due to willful neglect and was corrected during the 30-day period beginning on the first date the covered entity liable for the penalty knew, or, by exercising reasonable diligence, would have known that the violation occurred,

(A) In the amount of less than $10,000 or more than $50,000 for each violation; or

(B) In excess of $1,500,000 for identical violations during a calendar year (January 1 through the following December 31);

(iv) For a violation in which it is established that the violation was due to willful neglect and was not corrected during the 30-day period beginning on the first date the covered entity liable for the penalty knew, or, by exercising reasonable diligence, would have known that the violation occurred,

(A) In the amount of less than $50,000 for each violation; or

(B) In excess of $1,500,000 for identical violations during a calendar year (January 1 through the following December 31).

(3) If a requirement or prohibition in one administrative simplification provision is repeated in a more general form in another administrative simplification provision in the same subpart, a civil money penalty may be imposed for a violation of only one of these administrative simplification provisions.

■ 5. Revise § 160.410 to read as follows:

§ 160.410 Affirmative defenses.

(a) For violations occurring prior to February 18, 2009, the Secretary may not impose a civil money penalty on a covered entity for a violation if the covered entity establishes that an affirmative defense exists with respect to the violations, including the following:

(1) The violation is an act punishable under 42 U.S.C. 1320d–6;

(2) The covered entity establishes, to the satisfaction of the Secretary, that it did not have knowledge of the violation, determined in accordance with the federal common law of agency, and, by exercising reasonable diligence, would not have known that the violation occurred; or

(3) The violation is—

(i) Due to reasonable cause and not willful neglect; and

(ii) Corrected during either:

(A) The 30-day period beginning on the first date the covered entity liable for the penalty knew, or by exercising reasonable diligence would have known, that the violation occurred; or

(B) Such additional period as the Secretary determines to be appropriate based on the nature and extent of the failure to comply.

(b) For violations occurring on or after February 18, 2009, the Secretary may not impose a civil money penalty on a covered entity for a violation if the covered entity establishes that an affirmative defense exists with respect to the violations, including the following:

(1) The violation is an act punishable under 42 U.S.C. 1320d–6; or

(2) The covered entity establishes to the satisfaction of the Secretary that the violation is—

(i) Not due to willful neglect; and

(ii) Corrected during either:

(A) The 30-day period beginning on the first date the covered entity liable for the penalty knew, or, by exercising reasonable diligence, would have known that the violation occurred; or

(B) Such additional period as the Secretary determines to be appropriate based on the nature and extent of the failure to comply.

■ 6. Revise § 160.412 to read as follows:

§ 160.412 Waiver.

For violations due to reasonable cause and not willful neglect that are not corrected within the period described in § 160.410(a)(3)(ii) or (b)(2)(ii), as applicable, the Secretary may waive the civil money penalty, in whole or in part, to the extent that the payment of the penalty would be excessive relative to the violation.

■ 7. Revise § 160.420(a)(4) to read as follows:

§ 160.420 Notice of Proposed Determination.

(a) * * *

(4) The amount of the proposed penalty and a reference to the subparagraph of § 160.404 upon which it is based.

* * * * *

Dated: August 11, 2009.

Kathleen Sebelius,

Secretary.

[FR Doc. E9–26203 Filed 10–29–09; 8:45 am]

BILLING CODE 4150–03–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[MB Docket Nos. 07–294; 06–121; 02–277; 04–228; MM Docket Nos. 01–235; 01–317; 00–244; FCC 09–92]

Promoting Diversification of Ownership in the Broadcasting Services

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: This document reconsiders the requirement that licensees report certain nonattributable interests on FCC Form 323, Ownership Report for Commercial Broadcast Stations. Therefore, entities will not have to report these interests biennially on Form 323. The Commission reaffirms all other changes it made to the FCC Form 323 in the 323 Order.

DATES: The rule in this document contains information collection requirements that have been approved by the Office of Management and Budget (OMB). The rule will become effective upon publication of a document in the **Federal Register** announcing the OMB approval.

FOR FURTHER INFORMATION CONTACT: Mania Baghdadi, (202) 418–2330, Amy Brett, (202) 418–2300.

SUPPLEMENTARY INFORMATION: This is a summary of the Commission's Memorandum Opinion and Order in MB Docket Nos. 07–294; 06–121; 02–277; 04–228; MM Docket Nos. 01–235; 01–317; 00–244, FCC 09–92, adopted

October 15, 2009 and released October 16, 2009. The full text of this document is available for public inspection and copying during regular business hours in the FCC Reference Center, Federal Communications Commission, 445 12th Street, SW., CY–A257, Washington, DC 20554. These documents will also be available via ECFS (*http://www.fcc.gov/cgb/ecfs*). The complete text may be purchased from the Commission's copy contractor, 445 12th Street, SW., Room CY–B402, Washington, DC 20554.

Summary of the Memorandum Opinion and Order

1. In the MO&O, the Commission grants the National Association of Broadcaster's (NAB) Petition for Reconsideration to the extent that it requests reconsideration of the requirement that licensees report certain nonattributable interests. Otherwise, the Commission denies NAB's Petition, specifically its request to reconsider the requirement that sole proprietors file Form 323 ownership reports biennially. The Commission dismisses David Wilson's Petition for Reconsideration of the same requirement as repetitious.

2. The MO&O is an order on reconsideration of the 323 Order, in which the Commission adopted changes to the commercial broadcast ownership reporting requirements and delegated authority to the Media Bureau to revise FCC Form 323 accordingly. The Commission adopted these changes to increase the accuracy and comprehensiveness of the minority and female ownership data collected and to address other flaws in the data collection process as identified by the United States Government Accountability Office and by study authors who have attempted to use the current data to analyze broadcast ownership issues. Among other things, the Commission required sole proprietors and partnerships composed of natural persons to file Form 323 biennially, and it expanded the reporting requirement to include interests that are not attributable because of: (a) The single majority shareholder exemption; and (b) the exemption for interests held in eligible entities that would be attributable but for the higher Equity/Debt Plus (''EDP'') thresholds adopted in the Diversity Order for certain investments in eligible entities.

3. The Commission ratifies the Media Bureau's extension of the date for commercial licensees to file their initial biennial ownership reports on the new Form 323 to a date that is no earlier than 30 days after public notice of approval by OMB of the revised Form, with data current as of November 1, 2009. In the 323 Order, the Commission adopted a November 1, 2009 initial biennial filing date, requiring data to be current as of October 1, 2009. The deferral gives licensees and other entities sufficient time to review the new form and gather the necessary information. The extension of these deadlines will apply only to the initial filing. Beginning with the 2011 filing, the form must be filed no later than November 1 with data current as of October 1 of the filing year.

4. In the 323 Order, the Commission decided to require broadcasters to report every two years, on Form 323, information on entities with financial interests that would be attributable (1) but for the single majority shareholder attribution exemption or (2) the higher Equity/Debt Plus threshold adopted in the Diversity Order for purposes of attributing certain interests in eligible entities. NAB states that the Commission did not provide notice on this issue and that the record therefore lacks information as to potential harms or benefits of this new filing requirement. NAB expresses doubt that information from nonattributable entities will provide the Commission with any useful information on the current status of minority and female ownership of broadcast stations. NAB states that, by excluding these interests from its attribution rules, the Commission has already determined that such interests fail to confer sufficient influence over a licensee's operations. Therefore, NAB questions how the ownership information will further the Commission's stated goals. NAB is concerned that the reporting requirement will deter investment in the broadcast industry. If the Commission affirms its decision, NAB asks that reporting be limited to race, gender, and ownership percentage of the nonattributable investors, rather than full reporting of their names, addresses, familial relationships, and other media holdings.

5. Upon reconsideration, the Commission will delete the requirement that these two types of nonattributable interests be reported and modifies 73.3615 of the Commission's rules, accordingly. In the 323 Order, the Commission sought to revise Form 323 to ''obtain an accurate, reliable, and comprehensive assessment of minority and female broadcast ownership in the United States.'' The Commission concluded that gathering race, ethnicity, and gender data on the holders of these two types of interests would be useful in achieving this goal. While the Commission believes that this reporting requirement is a logical outgrowth of the Third Further Notice, it acknowledges that its intention to impose the requirement was not explicitly stated and notes that no comments specifically addressed the reporting of nonattributable interests. Therefore, the Commission separately issues a Further Notice to invite additional comment on this issue in order to obtain a complete record.

6. NAB also asks the Commission to reconsider the requirement that sole proprietors file ownership reports biennially. NAB also objects to sole proprietors having to update or refile after the initial filing on the new form. NAB is concerned that the biennial filing requirement will place a significant financial burden on sole proprietors, who may lack legal counsel or the personnel to track filing deadlines and other compliance matters. Instead, NAB proposes that the Commission incorporate in the database the most recently filed Form 323 for each licensee sole proprietor. NAB contends that the ownership report on file will provide current information on race, ethnicity, and gender, as these characteristics would not change over time. UCC disagrees with NAB that requiring sole proprietors to file Form 323 biennially creates significant burdens. UCC does not oppose NAB's suggestion that sole proprietors be allowed to link back to previously filed ownership reports, so long as the data ''quality, accuracy, accessibility and ease of use'' is not compromised.

7. The Commission reaffirms its decision to require sole proprietors to file Form 323 biennially. The revised Form 323 is intended to improve the quality, accuracy, and reliability of the information gathered over that collected in the old form, and it addresses the GAO Report and researcher's criticism that the existing data is difficult to aggregate and summarize. Pursuant to delegated authority, the Media Bureau revised and improved the instructions and questions in all sections of the form in order to: (1) Clarify the information sought in the form; (2) ensure that the data are collected in formats that can be easily incorporated in database programs used to prepare economic and policy studies and are not provided in unusable narrative exhibits; and (3) simplify completion of the form by giving respondents menu-style or checkbox-style options to enter data.

To further improve the ability of researchers and other users of the data to cross-reference information and construct complete ownership structures, the Media Bureau also is requiring each filing entity, including sole proprietors, to obtain a unique FCC

Registration Number (FRN) and to report the FRNs of entities one step above and one step below it in the ownership chain and to identify the FRNs of its attributable officers, directors, and shareholders. The uniform filing date and a uniform date ''as of'' which the data being reported must be accurate will allow comparisons of snapshots of all firms at uniform points in time and will facilitate long-term comparative studies of ownership.

8. Under NAB's approach, none of the ownership data on sole proprietors that would be included in the database immediately following the initial filing date would be submitted in the research-friendly format of the revised form, nor would it pass through the built-in quality control mechanisms in the revised form, and its submission would not be informed by the significantly improved instructions that are incorporated in the revised form. Absent the biennial filing requirement, it could be literally years before some sole proprietors would submit an ownership report using the non-biennial form, and even then race, ethnicity, and gender data would not be reported because, as a result of revisions made to the form pursuant to the 323 Order, non-biennial filers will not be required to provide this information. The Commission rejects NAB's approach that sole proprietors not update or refile after the initial filing on the new form. The biennial filing requirement will ensure that sole proprietors, like other filers, review and verify that the data on file are current. The verification process will greatly benefit efforts to improve the accuracy and reliability of the data collection. Without a periodical certification that the information is accurate, the Commission must assume that a lack of a filing constitutes a licensee's assurance that its information is current. However, the absence of a filing also could mean that the licensee failed to file a report, even though its ownership information had changed. The information could be out of date, and the Commission and public would have no assurance to the contrary.

9. The Commission also disagrees that the biennial filing requirement places an undue burden on sole proprietors. These licensees each have only one principal, therefore, determination of the relevant information should be a simple process. After the initial filing, these licensees, with current reports on file, simply must recertify, once every two years that they have reviewed their current reports and that they are accurate. Using the Commission's electronic filing system, a filer will launch a pre-filled form that already contains the information from its previously submitted Form 323. If all of the information is up to date, sole proprietors would then simply sign and electronically submit the pre-filled form. No additional data must be entered.

Final Paperwork Reduction Analysis

10. The MO&O contains revised information collection requirements subject to the Paperwork Reduction Act of 1995, Public Law 104–13. The revised information collection requirements will have the effect of reducing the paperwork burden. On August 11, 2009, the Commission submitted to the Office of Management and Budget (OMB) for review under Section 3507(d) of the PRA, the modified information collections pursuant to the 323 Order and published a notice in the **Federal Register** seeking comments on the August 11 submission. Due to public comments that were received with respect to FCC Form 323, the Commission further revised the information collection requirements that were contained in the 323 Order and amended the supporting statement and adjusted the burden hours and costs based on the revised information collection requirements contained in the MO&O.

Final Regulatory Flexibility Analysis

11. As required by the Regulatory Flexibility Act of 1980, as amended (RFA), prepared a Supplemental Final Regulatory Flexibility Analysis (Supplemental FRFA). The Supplemental FRFA addresses only the matters considered on reconsideration in this MO&O.

A. Need for, and Objectives of, the MO&O

12. The MO&O reaffirms its earlier conclusions in the 323 Order, except for one decision. In the 323 Order, the Commission decided to require broadcasters to report on Form 323 certain nonattributable interests and to require entities holding nonattributable interests to file Form 323. Specifically, the Commission required broadcasters to report every two years on Form 323 information on entities with financial interests that would be attributable (1) but for the single majority shareholder attribution exemption or (2) the higher Equity/Debt Plus threshold adopted in the Diversity Order for purposes of attributing certain interests in eligible entities. In addition, every two years, entities holding these interests would have to file Form 323. The 323 Order revised 47 CFR 73.3615 to implement this change. On reconsideration, the Commission determined that because no comments were filed on this issue, the record may not be complete. Therefore, the Commission will not require broadcasters to report these interests and will not require entities holding these interests to file Form 323. Instead, the Commission is issuing a further notice of proposed rulemaking to seek comment on this issue.

B. Legal Basis

13. This MO&O is adopted pursuant to 47 U.S.C. 151, 152(a), 154(i)–(j), 257, and 303(r).

C. Summary of Significant Issues Raised by Public Comments in Response to the FRFA

14. The Commission received no comments in direct response to the FRFA. No commenters addressed the impact of this reporting requirement on small entities in their comments generally.

D. Description and Estimate of the Number of Small Entities to Which the Rules Will Apply

15. The RFA directs agencies to provide a description of, and, where feasible, an estimate of the number of small entities that may be affected by the proposed rules, if adopted. The RFA defines the term ''small entity'' as having the same meaning as the terms ''small business,'' ''small organization,'' and ''small governmental entity'' under Section 3 of the Small Business Act. In addition, the term ''small business'' has the same meaning as the term ''small business concern'' under the Small Business Act. A small business concern is one which: (1) Is independently owned and operated; (2) is not dominant in its field of operation; and (3) satisfies any additional criteria established by the SBA.

16. Television Broadcasting. In this context, the application of the statutory definition to television stations is of concern. The Small Business Administration defines a television broadcasting station that has no more than $14 million in annual receipts as a small business. Business concerns included in this industry are those ''primarily engaged in broadcasting images together with sound.'' According to Commission staff review of the BIA Financial Network, Inc. Media Access Pro Television Database as of August 14, 2009, about 923 (72 percent) of the 1,289 commercial television stations in the United States have revenues of $14 million or less. The FCC notes that in assessing whether a business entity qualifies as small under the above

definition, business control affiliations must be included. The estimate, therefore, likely overstates the number of small entities that might be affected by any changes to the filing requirements for FCC Form 323, because the revenue figures on which this estimate is based do not include or aggregate revenues from affiliated companies.

17. An element of the definition of ''small business'' is that the entity not be dominant in its field of operation. The Commission is unable at this time and in this context to define or quantify the criteria that would establish whether a specific television station is dominant in its market of operation. Accordingly, the foregoing estimate of small businesses to which the rules may apply does not exclude any television stations from the definition of a small business on this basis and is therefore over-inclusive to that extent. An additional element of the definition of ''small business'' is that the entity must be independently owned and operated. It is difficult at times to assess these criteria in the context of media entities, and our estimates of small businesses to which they apply may be over-inclusive to this extent.

18. Radio Broadcasting. The Small Business Administration defines a radio broadcasting entity that has $7 million or less in annual receipts as a small business. Business concerns included in this industry are those ''primarily engaged in broadcasting aural programs by radio to the public.'' According to Commission staff review of the BIA Financial Network, Inc. Media Access Radio Analyzer Database as of August 14, 2009, about 10,660 (96 percent) of 11,100 commercial radio stations in the United States have revenues of $7 million or less. The FCC notes that in assessing whether a business entity qualifies as small under the above definition, business control affiliations must be included. The estimate, therefore, likely overstates the number of small entities that might be affected by any changes to the ownership rules, because the revenue figures on which this estimate is based do not include or aggregate revenues from affiliated companies.

19. In this context, the application of the statutory definition to radio stations is of concern. An element of the definition of ''small business'' is that the entity not be dominant in its field of operation. The FCC is unable at this time and in this context to define or quantify the criteria that would establish whether a specific radio station is dominant in its field of operation. Accordingly, the foregoing estimate of small businesses to which the rules may apply does not exclude any radio station from the definition of a small business on this basis and is therefore over-inclusive to that extent. An additional element of the definition of ''small business'' is that the entity must be independently owned and operated. It is difficult at times to assess these criteria in the context of media entities, and our estimates of small businesses to which they apply may be over-inclusive to this extent.

20. *Class A TV and LPTV stations.* The rules and policies adopted herein apply to licensees of Class A TV stations and low power television (''LPTV'') stations, as well as to potential licensees in these television services. The same SBA definition that applies to television broadcast licensees would apply to these stations. The SBA defines a television broadcast station as a small business if such station has no more than $14.0 million in annual receipts. As of June 30, 2009, there are approximately 553 licensed Class A stations and 2,386 licensed LPTV stations. Given the nature of these services, the FCC presumes that all of these licensees qualify as small entities under the SBA definition. However, under the SBA's definition, revenue of affiliates that are not LPTV stations should be aggregated with the LPTV station revenues in determining whether a concern is small. The estimate may thus overstate the number of small entities since the revenue figure on which it is based does not include or aggregate revenues from non-LPTV affiliated companies.

E. Description of Projected Reporting, Recordkeeping and Other Compliance Requirements

21. The MO&O eliminates one of the reporting, recordkeeping and compliance requirements adopted in the 323 Order. Licensees will not be required to report holders of two classes of nonattributable ownership interests: (1) Equity interests in a licensee that would be attributable but for the single majority shareholder exemption and (2) interests that would be attributable but for the higher Equity/Debt Plus thresholds adopted in the Diversity Order for purposes of determining attribution of certain interests in eligible entities. Thus, the FCC has reduced the reporting and recordkeeping requirements associated with this form.

F. Steps Taken To Minimize Significant Impact on Small Entities and Significant Alternatives Considered

22. The RFA requires an agency to describe any significant alternatives that it has considered in reaching its proposed approach, which may include the following four alternatives (among others): (1) The establishment of differing compliance or reporting requirements or timetables that take into account the resources available to small entities; (2) the clarification, consolidation, or simplification of compliance and reporting requirements under the rule for small entities; (3) the use of performance, rather than design, standards; and (4) an exemption from coverage of the rule, or any part thereof, for small entities.

23. On reconsideration, the Commission reversed its decision in the 323 Order to require reporting of certain nonattributable interests. The FCC believes that it is preferable to seek additional comment on this issue in a further notice of proposed rulemaking to develop a full record on this issue, and not require broadcasters to file this information based on the current record in this proceeding. The MO&O reduces the burdens on small entities because these entities will not have to report on certain nonattributable interests and holders of those interests will not have to file Form 323 every two years.

G. Report to Congress

24. The Commission will send a copy of the MO&O, including the Supplemental FRFA, in a report to Congress and the Government Accountability Office, pursuant to the Congressional Review Act. In addition, the Commission will send a copy of the MO&O, including the Supplemental FRFA, to the Chief Counsel for Advocacy of the Small Business Administration.

List of Subjects in 47 CFR Part 73

Radio, Television.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

Final Rule

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

PART 73—RADIO BROADCAST SERVICES

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

Authority: 47 U.S.C. 154, 303, 334, 336 and 339.

■ 2. Section 73.3615 is amended by revising paragraph (a) introductory text to read as follows:

§ 73.3615 Ownership reports.

(a) The Ownership Report for Commercial Broadcast Stations (FCC Form 323) must be electronically filed every two years by each licensee of a commercial AM, FM, or TV broadcast station (a ''Licensee''); and each entity that holds an interest in the licensee that is attributable for purposes of determining compliance with the Commission's multiple ownership rules (see Notes 1–3 to 47 CFR 73.3555) (a ''Respondent''). The initial filing deadline shall be set by Public Notice issued by the Media Bureau. Thereafter, the Form shall be filed biennially by November 1, 2011, and every two years thereafter. A Licensee or Respondent with a current and unamended Report on file at the Commission, which was filed on or by the initial filing date or thereafter, using the Form revised pursuant to the Commission's Orders in MB Docket Nos. 07–294, *et al.,* 24 FCC Rcd 5896 (2009) (FCC 09–92, rel. Oct. 16, 2009), and which is still accurate, may electronically validate and resubmit its previously filed Form 323. Ownership Reports shall provide the following information as of October 1 of the year in which the Report is filed, except that the Form filed by the initial filing date shall provide the following information as of November 1, 2009:

* * * * *

[FR Doc. E9–26071 Filed 10–29–09; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[MB Docket Nos. 07–294, 06–121, 02–277, 04–228; MM Docket Nos. 01–235, 01–317, 00–244; FCC 09–92]

Promoting Diversification of Ownership in Broadcast Services

AGENCY: Federal Communications Commission.

ACTION: Final rule; announcement of effective date.

SUMMARY: In this document, the Commission announces that the Office of Management and Budget (OMB) has approved, for a period of three years, the information collection, FCC Form 323, associated with 47 CFR 73.3615. Therefore, this rule and FCC Form 323 will take effect on October 30, 2009. A summary document of the Memorandum Opinion and Order, *In the Matter of Promoting Diversification of Ownership in the Broadcasting Services* in MB Docket Nos. 07–294, 06–121, 02–277, 04–228; MM Docket Nos. 01–235, 01–317, 00–244; FCC 09–92 is published elsewhere in this issue of the **Federal Register**. The summary document of the *Memorandum Opinion and Order* states that the information collection requirements have been approved by OMB and that the Commission will publish a notice in the **Federal Register** announcing the effective date. This notification is consistent with the statement in that document, published elsewhere in this issue of the **Federal Register**.

DATES: The amendments to 47 CFR 73.3615 and FCC Form 323, published May 27, 2009, 74 FR 25163, are effective on October 30, 2009.

FOR FURTHER INFORMATION CONTACT: For additional information, please contact Cathy Williams, *cathy.williams@fcc.gov* or on (202) 418–2918.

SUPPLEMENTARY INFORMATION: This document announces that, on October 19, 2009, OMB approved, for a period of three years, the information collection, FCC Form 323, associated with Section 73.3615 of the FCC rules. The Commission publishes this notice to announce the effective date of these rules and Form 323.

Synopsis

As required by the Paperwork Reduction Act of 1995 (44 U.S.C. 3507), the Commission is notifying the public that it received OMB approval on October 19, 2009, for the information collection, FCC Form 323, associated with 47 CFR 73.3615.

Under 5 CFR 1320, an agency may not conduct or sponsor a collection of information unless it displays a current, valid OMB Control Number.

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

The OMB Control Number is 3060–0010 and the total annual reporting burdens for respondents for this information collection are as follows:

OMB Control Number: 3060–0010.

OMB Approval Date: October 19, 2009.

Expiration Date: October 31, 2012.

Title: Ownership Report for Commercial Broadcast Stations.

Form Number: FCC Form 323.

Type of Review: Revision of a currently approved collection.

Respondents: Business or other for-profit entities; not-for-profit institutions; State, Local or Tribal Governments.

Number of Respondents/Responses: 9,250 respondents; 9,250 responses.

Estimated Time per Response: 2.5 hours to 4.5 hours.

Frequency of Response: Recordkeeping requirement; on occasion reporting requirement; biennial reporting requirement.

Total Annual Burden: 38,125 hours.

Total Annual Costs: $26,940,000.

Obligation to Respond: Required to obtain or retain benefits. Statutory authority for this collection of information is contained in Sections 154(i), 303 and 310 of the Communications Act of 1934, as amended.

Nature and Extent of Confidentiality: Form 323 collects two types of information (among others) from respondents: (a) Personal information in the form of names, addresses, job titles and demographic information; and (b) FCC Registration Numbers (FRNs).

Confidentiality is an issue to the extent that individuals provide personally identifiable information which will be covered under the FCC's pending system of records (SORN), FCC/MB–1, ''Ownership Report for Commercial Broadcast Stations.'' FRNs are covered under FCC's system of records (SORN), FCC/OMD–9, ''Commission Registration System (CORES).''

Privacy Act Impact Assessment: This information collection contains personally identifiable information on individuals (''PII'').

(a) As noted above, the FCC is in the process of establishing a System of Records, FCC/MB–1, ''Ownership Report for Commercial Broadcast Stations,'' to cover the collection, purpose(s), storage, safeguards, and disposal of the PII that individual respondents may submit on FCC Form 323.

(b) The SORN will be published in the **Federal Register** at a subsequent date.

Needs and Uses: On April 8, 2009, the Commission adopted a *Report and Order and Fourth Further Notice of Proposed Rulemaking* in MB Docket Nos. 07–294, 06–121, 02–277, 01–235, 01–317, 00–244, 04–228; FCC 09–33; 24 FCC Rcd 5896 (2009). The *323 Order* directs the Commission to revise Form 323 to improve the quality of the data collected in order to obtain an accurate, reliable, and comprehensive assessment of minority and female broadcast ownership in the United States. Specifically, the Commission changed the biennial reporting requirements on Form 323 so that there is a uniform filing date; broadened the biennial reporting requirements to include commercial broadcast licensees that are sole proprietorships and partnerships comprised of natural persons; expanded the class of persons and entities that must file to include low power television stations (''LPTV'') licensees, including Class A stations; and provided that the form should be electronically searchable and that there should be edit checks built in. The Commission also adopted changes requiring certain non-attributable interests to be reported on biennially-filed Form 323s.

On October 16, 2009, the Commission adopted a *Reconsideration Order* in response to a Petition for Reconsideration filed by the National Association of Broadcasters. *In re Promoting Diversification of Ownership in the Broadcasting Services,* Memorandum Opinion and Order and Fifth Further Notice of Proposed Rulemaking in MB Docket Nos. 07–294, 06–121, 02–277, 01–235, 01–317, 00–244, 04–228; FCC 09–92 (Rel. Oct. 16, 2009). The *Reconsideration Order* eliminates the requirement that certain non-attributable interests (voting stock interests that would be attributable but for the operation of the single majority shareholder attribution exemption and equity and/or debt interests that would be attributable but for the exemption for certain investments in eligible entities) must be reported on biennially-filed Form 323s. The Commission agreed that it was advisable to invite additional comment from the public on requiring reporting of these nonattributable interests and issued a *Fifth Further Notice of Proposed Rulemaking* inviting such further comment.

Consistent with actions taken by the Commission described above, the following changes are made to Form 323: The Instructions and questions in all sections of the form have been significantly revised. The instructions to Form 323 have been revised to incorporate a definition of ''eligible entity,'' which will apply to the Commission's existing Equity Debt Plus (''EDP'') standard, one of the standards used to determine whether interests in a media entity are attributable. The instructions to Form 323 have also been revised slightly to provide updated citations to the Commission's applicable rules governing media ownership. The instructions for Section I have been revised to state the Commission's revised biennial filing requirements adopted in the 323 Order. Many questions on the form have been reworked or reordered in order to (1) clarify the information sought in the form; (2) simplify completion of the form by giving respondents menu-style or checkbox-style options to select rather than submit a separate narrative exhibit; and (3) make the data collected on the form more adaptable for use in database programs used to prepare economic and policy studies relating to media ownership. The instructions to the Form have been revised to make them clearer and easier to follow by going question-by-question and having each instruction correspond to a relevant question. In addition, portions of the Form that relate only to non-biennial or to biennial filings separately have been placed into separate subsections of the Form. Respondents using the Commission's electronic filing system will be required to launch only the portions of the form that are applicable depending on the purpose of the filing (i.e., whether it is a biennial filing or a non-biennial filing) and complete only those sections.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

[FR Doc. E9–26196 Filed 10–29–09; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Parts 73 and 74

[MB Docket Nos. 07–294, 06–121, 02–277, 04–228; MM Docket Nos. 01–235, 01–317, 00–244; FCC 09–33]

Promoting Diversification of Ownership in Broadcast Services

AGENCY: Federal Communications Commission.

ACTION: Final rule; announcement of effective date.

SUMMARY: In this document, the Commission announces that the Office of Management and Budget (OMB) has approved, for a period of three years, the information collection, FCC Form 323, associated with 47 CFR Sections 73.6026 and 74.797. Therefore, these rules and FCC Form 323 will take effect on October 30, 2009. The Commission published summary documents of *Report and Order, In the Matter of Promoting Diversification of Ownership in the Broadcasting Services* in MB Docket Nos. 07–294, 06–121, 02–277, 04–228; MM Docket Nos. 01–235, 01–317, 00–244; FCC 09–33 on May 27, 2009. The published summary document of the *Report and Order* stated that the information collection requirements required approval by OMB and that the FCC will publish a document in the **Federal Register** announcing the effective date. The Commission subsequently received OMB approval. This notification is consistent with that statement in the summary document, published May 27, 2009. 47 CFR 73.3615 was also included in the Report and Order. However, the Commission issued a Memorandum Opinion and Order which revised that rule section. A notice announcing the effective date of that rule section is published elsewhere in this issue of the **Federal Register**.

DATES: The amendments to 47 CFR 73.6026 and 74.797 and FCC Form 323 published May 27, 2009, 74 FR 25163, are effective on October 30, 2009.

FOR FURTHER INFORMATION CONTACT: For additional information, please contact Cathy Williams, *cathy.williams@fcc.gov* or on (202) 418–2918.

SUPPLEMENTARY INFORMATION: This document announces that, on October 19, 2009, OMB approved, for a period of three years, the information collection, FCC Form 323, associated with Sections 73.6026 and 74.797 of the FCC rules. The Commission publishes this notice to announce the effective date of these rules and Form 323.

Synopsis

As required by the Paperwork Reduction Act of 1995 (44 U.S.C. 3507), the Commission is notifying the public that it received OMB approval on October 19, 2009, for the information collection, FCC Form 323, associated with 47 CFR Sections 73.6026 and 74.797. Under 5 CFR 1320, an agency may not conduct or sponsor a collection of information unless it displays a current, valid OMB Control Number.

No person shall be subject to any penalty for failing to comply with a collection of information subject to the Paperwork Reduction Act that does not display a valid OMB Control Number. The OMB Control Number is 3060–0010 and the total annual reporting burdens for respondents for this information collection are as follows:

OMB Control Number: 3060–0010.

OMB Approval Date: October 19, 2009.

Expiration Date: October 31, 2012.

Title: Ownership Report for Commercial Broadcast Stations.

Form Number: FCC Form 323.

Type of Review: Revision of a currently approved collection.

Respondents: Business or other for-profit entities; Not-for-profit institutions; State, Local or Tribal Governments.

Number of Respondents/Responses: 9,250 respondents; 9,250 responses.

Estimated Time per Response: 2.5 hours to 4.5 hours.

Frequency of Response: Recordkeeping requirement; On occasion reporting requirement; Biennial reporting requirement.

Total Annual Burden: 38,125 hours.

Total Annual Costs: $26,940,000.

Obligation to Respond: Required to obtain or retain benefits. Statutory authority for this collection of information is contained in Sections 154(i), 303 and 310 of the Communications Act of 1934, as amended.

Nature and Extent of Confidentiality: Form 323 collects two types of information (among others) from respondents: (a) Personal information in the form of names, addresses, job titles and demographic information; and (b) FCC Registration Numbers (FRNs). Confidentiality is an issue to the extent that individuals provide personally identifiable information which will be covered under the FCC's pending system of records (SORN), FCC/MB–1, ''Ownership Report for Commercial Broadcast Stations.'' FRNs are covered under FCC's system of records (SORN), FCC/OMD–9, ''Commission Registration System (CORES).''

Privacy Act Impact Assessment: This information collection contains personally identifiable information on individuals (''PII'').

(a) As noted above, the FCC is in the process of establishing a System of Records, FCC/MB–1, ''Ownership Report for Commercial Broadcast Stations,'' to cover the collection, purpose(s), storage, safeguards, and disposal of the PII that individual respondents may submit on FCC Form 323.

(b) The SORN will be published in the **Federal Register** at a subsequent date.

Needs and Uses

On April 8, 2009, the Commission adopted a *Report and Order and Fourth Further Notice of Proposed Rulemaking* in MB Docket Nos. 07–294, 06–121, 02–277, 01–235, 01–317, 00–244, 04–228; FCC 09–33; 24 FCC Rcd 5896 (2009). The *323 Order* directs the Commission to revise Form 323 to improve the quality of the data collected in order to obtain an accurate, reliable, and comprehensive assessment of minority and female broadcast ownership in the United States. Specifically, the Commission changed the biennial reporting requirements on Form 323 so that there is a uniform filing date; broadened the biennial reporting requirements to include commercial broadcast licensees that are sole proprietorships and partnerships comprised of natural persons; expanded the class of persons and entities that must file to include low power television stations (''LPTV'') licensees, including Class A stations; and provided that the form should be electronically searchable and that there should be edit checks built in. The Commission also adopted changes requiring certain non-attributable interests to be reported on biennially-filed Form 323s.

On October 16, 2009, the Commission adopted a *Reconsideration Order* in response to a Petition for Reconsideration filed by the National Association of Broadcasters. *In re Promoting Diversification of Ownership in the Broadcasting Services,* Memorandum Opinion and Order and Fifth Further Notice of Proposed Rulemaking in MB Docket Nos. 07–294, 06–121, 02–277, 01–235, 01–317, 00–244, 04–228; FCC 09–92 (Rel. Oct. 16, 2009). The *Reconsideration Order* eliminates the requirement that certain non-attributable interests (voting stock interests that would be attributable but for the operation of the single majority shareholder attribution exemption and equity and/or debt interests that would be attributable but for the exemption for certain investments in eligible entities) must be reported on biennially-filed Form 323s. The Commission agreed that it was advisable to invite additional comment from the public on requiring reporting of these nonattributable interests and issued a *Fifth Further Notice of Proposed Rulemaking* inviting such further comment.

Consistent with actions taken by the Commission described above, the following changes are made to Form 323: The Instructions and questions in all sections of the form have been significantly revised. The instructions to Form 323 have been revised to incorporate a definition of ''eligible entity,'' which will apply to the Commission's existing Equity Debt Plus (''EDP'') standard, one of the standards used to determine whether interests in a media entity are attributable. The instructions to Form 323 have also been revised slightly to provide updated citations to the Commission's applicable rules governing media ownership. The instructions for Section I have been revised to state the Commission's revised Biennial filing requirements adopted in the 323 Order. Many questions on the form have been reworked or reordered in order to (1) clarify the information sought in the form; (2) simplify completion of the form by giving respondents menu-style or checkbox-style options to select rather than submit a separate narrative exhibit; and (3) make the data collected on the form more adaptable for use in database programs used to prepare economic and policy studies relating to media ownership. The instructions to the Form have been revised to make them clearer and easier to follow by going question-by-question and having each instruction correspond to a relevant question. In addition, portions of the Form that relate only to non-biennial or to biennial filings separately have been placed into separate subsections of the Form. Respondents using the Commission's electronic filing system will be required to launch only the portions of the form that are applicable depending on the purpose of the filing (*i.e.,* whether it is a biennial filing or a non-biennial filing) and complete only those sections.

Marlene H. Dortch,

Secretary, Federal Communications Commission.

[FR Doc. E9–26198 Filed 10–29–09; 8:45 am]

BILLING CODE 6712–01–P

Proposed Rules

Federal Register

Vol. 74, No. 209

Friday, October 30, 2009

This section of the FEDERAL REGISTER contains notices to the public of the proposed issuance of rules and regulations. The purpose of these notices is to give interested persons an opportunity to participate in the rule making prior to the adoption of the final rules.

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2009–1015; Directorate Identifier 2009–CE–039–AD]

RIN 2120–AA64

Airworthiness Directives; Piper Aircraft, Inc. PA–28, PA–32, PA–34 and PA–44 Series Airplanes

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: We propose to adopt a new airworthiness directive (AD) for certain Piper Aircraft, Inc. (Piper) PA–28, PA–32, PA–34 and PA–44 series airplanes. This proposed AD would require an inspection of the control wheel shaft for both the pilot and copilot sides and, if necessary, replacement of the control wheel shaft. This proposed AD results from two field reports of incorrectly assembled control wheel shafts. We are proposing this AD to detect and correct any incorrectly assembled control wheel shafts. This condition, if left uncorrected, could lead to separation of the control wheel shaft, resulting in loss of pitch and roll control.

DATES: We must receive comments on this proposed AD by December 29, 2009.

ADDRESSES: Use one of the following addresses to comment on this proposed AD:

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

For service information identified in this proposed AD, contact Piper Aircraft, Inc., 2926 Piper Drive, Vero Beach, Florida 32960; *telephone:* (772) 567–4361; *fax:* (772) 978–6573; *Internet: http://www.newpiper.com/company/publications.asp.*

FOR FURTHER INFORMATION CONTACT: Hector Hernandez, Aerospace Engineer, Atlanta Aircraft Certification Office (ACO), 1701 Columbia Avenue, College Park, GA 30337; *telephone:* (404) 474–5587; *fax:* (404) 474–5606.

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to send any written relevant data, views, or arguments regarding this proposed AD. Send your comments to an address listed under the **ADDRESSES** section. Include the docket number, ‘‘FAA–2009–1015; Directorate Identifier 2009–CE–039–AD’’ at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of the proposed AD. We will consider all comments received by the closing date and may amend the proposed AD in light 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 we receive concerning this proposed AD.

Discussion

We have received two reports of control wheel shafts that have been incorrectly assembled at Piper. The first incident concerned the loss of the control wheel on a Piper Model PA–34–220T airplane, where the right-hand control wheel shaft and universal joint separated due to a misdrilled hole for the threaded taper pin. The second report was of a ground inspection on a Piper PA–34–220T airplane that revealed a similar situation between the control wheel shaft and the universal joint in the left-hand side. Investigation following these reports revealed that the control wheel shafts had been incorrectly assembled at Piper and holes were misdrilled even though they may visually appear acceptable. The hole in the shaft may be too close to the end of the shaft, causing a significant reduction in joint strength. Since discovery of this problem, Piper has added a step to the manufacturing process and also introduced a fixture to ensure proper assembly of the control wheel shaft/universal joint.

This condition, if not corrected, could result in separation of the control wheel shaft, resulting in loss of pitch and roll control.

Relevant Service Information

We have reviewed Piper Aircraft, Inc. Service Bulletin No. 1197A, dated September 1, 2009.

The service information describes procedures for:

- Inspection on both the pilot and copilot control wheel columns; and
- If necessary, replacement of the control wheel shaft and the universal joint.

FAA's Determination and Requirements of the Proposed AD

We are proposing this AD because we evaluated all information and determined the unsafe condition described previously is likely to exist or develop on other products of the same type design. This proposed AD would require a mandatory inspection of the control wheel shaft for both the pilot and copilot sides. This proposed AD results from two field reports of incorrectly assembled control wheel shafts. We are proposing this AD to detect and correct any incorrectly assembled control wheel shafts. This condition, if left uncorrected, could lead to separation of the control wheel shaft, resulting in loss of pitch and roll control.

Costs of Compliance

We estimate that this proposed AD would affect 41,928 airplanes in the U.S. registry.

We estimate the following costs to do the proposed inspection:

Labor cost	Parts cost	Total cost per airplane	Total cost on U.S. operators
0.5 work-hour × $80 per hour = $40	Not applicable	$40	$1,677,120

We estimate the following costs to do any necessary replacements that would be required based on the results of the proposed inspection. We have no way of determining the number of airplanes that may need this repair/replacement:

Labor cost	Parts cost	Total cost per airplane
16 work-hours × $80 per hour = $1,280	$150	$1,430

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

For the reasons discussed above, I certify that the proposed regulation:

1. Is not a ''significant regulatory action'' under Executive Order 12866;

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

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

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

Examining the AD Docket

You may examine the AD docket that contains the proposed AD, the regulatory evaluation, any comments received, and other information on the Internet at *http://www.regulations.gov*; or in person at the Docket Management Facility between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The Docket Office (telephone (800) 647–5527) is located at the street address stated in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

List of Subjects in 14 CFR Part 39

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

The Proposed Amendment

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

PART 39—AIRWORTHINESS DIRECTIVES

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

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

§ 39.13 [Amended]

2. The FAA amends § 39.13 by adding the following new AD:

Piper Aircraft, Inc.: Docket No. FAA–2009–1015; Directorate Identifier 2009–CE–039–AD.

Comments Due Date

(a) We must receive comments on this airworthiness directive (AD) action by December 29, 2009.

Affected ADs

(b) None.

Applicability

(c) This AD applies to the following airplane models and serial numbers that are certificated in any category:

Models	Serial Nos.
PA–28–140	28–20001 through 28–26946 and 28–7125001 through 28–7725290.
PA–28–150	28–03; 28–1 through 28–4377; and 28–1760A.
PA–28–160	28–03; 28–1 through 28–4377; and 28–1760A.
PA–28–180	28–03; 28–671 through 28–5859; and 28–7105001 through 28–7205318.
PA–28S–160	28–1 through 28–1760 and 28–1760A.
PA–28S–180	28–671 through 28–5859 and 28–7105001 through 28–7105234.
PA–28–235	28–10001 through 28–11378; 28–7110001 through 28–7210023; 28E–11 and 28–7310001 through 28–7710089.
PA–28–236	28–7911001 through 28–8611008 and 2811001 through 2811050.
PA–28–151	28–7415001 through 28–7715314.
PA–28–161	2841001 through 2841365; 28–7716001 through 28–8216300; 28–8316001 through 28–8616057; 2816001 through 2816109; 2816110 through 2816119; and 2842001 through 2842305.
PA–28–180	28–E13 and 28–7305001 through 28–7505260.
PA–28–181	28–7690001 through 28–8690056; 28–8690061; 28–8690062; 2890001 through 2890205; 2890206 through 2890231; and 2843001 through 2843672.
PA–28–201T	28–7921001 through 28–7921095.
PA–28R–180	28R–30002 through 28R–31270 and 28R–7130001 through 28R–7130013.
PA–28R–200	28R–35001 through 28R–35820; 28R–7135001 through 28R–7135229; and 28R–7235001 through 28R–7635545.

Models	Serial Nos.
PA–28R–201	28R–7737002 through 28R–7837317; 2837001 through 2837061; and 2844001 through 2844138.
PA–28R–201T	28R–7703001 through 28R–7803374 and 2803001 through 2803012.
PA–28RT–201	28R–7918001 through 28R–7918267 and 28R–8018001 through 28R–8218026.
PA–28RT–201T	28R–7931001 through 28R–8631005 and 2831001 through 2831038.
PA–32–260	32–03; 32–04; 32–1 through 32–1297; and 32–7100001 through 32–7800008.
PA–32–300	32–15; 32–21; 32–40000 through 32–40974; and 32–7140001 through 32–7940290.
PA–32S–300	32S–15; 32S–40000 through 32S–40974; and 32S–7140001 through 32S–7240137.
PA–32R–300	32R–7680001 through 32R–7880068.
PA–32RT–300	32R–7885002 through 32R–7985106.
PA–32RT–300T	32R–7787001 and 32R–7887002 through 32R–7987126.
PA–32R–301 (SP)	32R–8013001 through 32R–8613006; 3213001 through 3213028; and 3213030 through 3213041.
PA–32R–301 (HP)	3213029; 3213042 through 3213103; 3246001 through 3246217; 3246219; 3246223; 3246218; 3246220 through 3246222; and 3246224 through 3246244.
PA–32R–301T	32R–8029001 through 32R–8629008 and 3229001 through 3229003.
PA–32–301	32–8006002 through 32–8606023; 3206001 through 3206019; 3206042 through 3206044; 3206047; 3206050 through 3206055; and 3206060.
PA–32–301T	32–8024001 through 32–8424002.
PA–32R–301T	3257001 through 3257483.
PA–32–301FT	3232001 through 3232074.
PA–32–301XTC	3255001 through 3255014; 3255026, 3255015 through 3255025; 3255027; and 3255051.
PA–34–200	34–E4 and 34–7250001 through 34–7450220.
PA–34–200T	34–7570001 through 34–8170092.
PA–34–220T	34–8133001 through 34–8633031; 3433001 through 3433172; 3448001 through 3448037; 3448038 through 3448079; 3447001 through 3447029; and 3449001 through 3449377.
PA–44–180	44–7995001 through 44–8195026; 4495001 through 4495013; and 4496001 through 4496251.
PA–44–180T	44–8107001 through 44–8207020.

Unsafe Condition

(d) This AD results from two field reports of incorrectly assembled control wheel shafts. We are issuing this AD to detect and correct any incorrectly assembled control wheel shafts. This condition, if left uncorrected, could lead to separation of the control wheel shaft, resulting in loss of pitch and roll control.

Compliance

(e) To address this problem, you must do the following, unless already done:

Actions	Compliance	Procedures
(1) Inspect the pilot and copilot control wheel columns for correct control wheel shaft installation.	Within 100 hours time-in-service (TIS) after the effective date of this AD or within 60 days after the effective date of this AD, whichever occurs first.	Follow Piper Aircraft, Inc. Mandatory Service Bulletin No. 1197A, dated September 1, 2009.
(2) If during the inspection required in paragraph (e)(1) of this AD an incorrectly installed control wheel shaft is found, replace the appropriate shaft with a new shaft.	Before further flight after any inspection that finds incorrect installation of the control wheel shaft.	Follow Piper Aircraft, Inc. Mandatory Service Bulletin No. 1197A, dated September 1, 2009.
(3) Inspect the universal joint when doing the action required in (e)(2) of this AD, and if any deterioration, excessive wear, or damage is found, replace the universal joint with a new universal joint.	Before further flight after any inspection that finds incorrect installation of the control wheel shaft.	Follow Piper Aircraft, Inc. Mandatory Service Bulletin No. 1197A, dated September 1, 2009.

Alternative Methods of Compliance (AMOCs)

(f) The Manager, Atlanta Aircraft Certification Office (ACO), FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. Send information to *Attn:* Hector Hernandez, Aerospace Engineer, Atlanta Aircraft Certification Office (ACO), 1701 Columbia Avenue, College Park, GA 30337; *telephone:* (404) 474–5587; *fax:* (404) 474–5606. Before using any approved AMOC on any airplane to which the AMOC applies, notify your appropriate principal inspector (PI) in the FAA Flight Standards District Office (FSDO), or lacking a PI, your local FSDO.

Related Information

(g) To get copies of the service information referenced in this AD, contact Piper Aircraft, Inc., 2926 Piper Drive, Vero Beach, Florida 32960; *telephone:* (772) 567–4361; *fax:* (772) 978–6573; *Internet: http://www.newpiper.com/company/publications.asp.* To view the AD docket, go to U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590, or on the Internet at *http://www.regulations.gov.*

Issued in Kansas City, Missouri, on October 23, 2009.

Kim Smith,

Manager, Small Airplane Directorate, Aircraft Certification Service.

[FR Doc. E9–26200 Filed 10–29–09; 8:45 am]

BILLING CODE 4910–13–P

SOCIAL SECURITY ADMINISTRATION

20 CFR Parts 404, 405, and 416

[Docket No. SSA–2007–0053]

Compassionate Allowances for Schizophrenia; Office of the Commissioner, Hearing

AGENCY: Social Security Administration (SSA).

ACTION: Announcement of public hearing.

SUMMARY: We are considering ways to quickly identify diseases and other serious medical conditions that obviously meet the definition of disability under the Social Security Act (Act) and can be identified with

minimal objective medical information. We are calling this method ''Compassionate Allowances.'' In December 2007, April 2008, November 2008, and July 2009, we held Compassionate Allowance public hearings. These hearings concerned rare diseases, cancers, traumatic brain injury and stroke, early-onset alzheimer's and related dementias, respectively. This hearing is the fifth in the series. The purpose of this hearing is to obtain your views about the advisability and possible methods of identifying and implementing compassionate allowances for young adults with Schizophrenia. We plan to address other medical conditions at subsequent hearings.

DATES: This hearing will be held on November 18, 2009, between 8:30 a.m. and 5 p.m., Pacific Standard Time (PST), in San Francisco, CA. The hearing will be held at the Parc 55 Hotel in the Cyril Magnin Room. The hotel's address is 55 Cyril Magnin Street, San Francisco, CA 94102. While the public is welcome to attend the hearing, only invited witnesses will present testimony. You may also watch the proceedings live via Webcast beginning at 9 a.m., Pacific Standard Time (PST). You may access the Webcast line for the hearing on the Social Security Administration Web site at *http://www.socialsecurity.gov/compassionateallowances/hearings.htm.*

ADDRESSES: You may submit written comments about the compassionate allowances initiative with respect to young adults with Schizophrenia, as well as topics covered at the hearing by (1) e-mail addressed to *Compassionate.Allowances@ssa.gov*; *or* (2) mail to Nancy Schoenberg, Acting Director, Office of Compassionate Allowances and Disability Outreach, ODP, ORDP, Social Security Administration, 4671 Annex Building, 6401 Security Boulevard, Baltimore, MD 21235–6401. We welcome your comments, but we may not respond directly to comments sent in response to this notice of the hearing.

FOR FURTHER INFORMATION CONTACT: *Compassionate.Allowances@ssa.gov*. You may also mail inquiries about this meeting to Nancy Schoenberg, Acting Director, Office of Compassionate Allowances and Disability Outreach, ODP, ORDP, Social Security Administration, 4671 Annex, 6401 Security Boulevard, Baltimore, MD 21235–6401. For information on eligibility or filing for benefits, call our national toll-free number 1–800–772–1213 or TTY 1–800–325–0778, or visit Social Security online, at *http://www.socialsecurity.gov*.

SUPPLEMENTARY INFORMATION:

Background

Under titles II and XVI of the Act, we pay benefits to individuals who meet our rules for entitlement and have medically determinable physical or mental impairments that are severe enough to meet the definition of disability in the Act. The rules for determining disability can be very complicated, but some individuals have such serious medical conditions that their conditions obviously meet our disability standards. To better address the needs of these individuals, we are implementing the Compassionate Allowance initiative to quickly identify diseases and other medical conditions that invariably qualify under the Listing of Impairments based on minimal objective medical information.

Will We Respond to Your Comments?

We will carefully consider your comments, although we will not respond directly to comments sent in response to this notice or the hearing.

Additional Hearings

We have held four hearings since December 2007. The hearings were on rare diseases, cancers, and traumatic brain injury (TBI) and stroke, early-onset alzheimer's and related dementias. You may access the transcripts of the hearings at *http://www.socialsecurity.gov/compassionateallowances.* We plan to hold additional hearings on other conditions and will announce those hearings later with notices in the **Federal Register**.

(Catalog of Federal Domestic Assistance Program Nos. 96.001, Social Security—Disability Insurance; 96.006, Supplemental Security Income. (72 FR at 62608).

Dated: October 26, 2009.

Michael J. Astrue,

Commissioner of Social Security.

[FR Doc. E9–26194 Filed 10–29–09; 8:45 am]

BILLING CODE 4191–02–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

42 CFR Part 84

RIN 0920–AA33

Total Inward Leakage Requirements for Respirators

AGENCY: Centers for Disease Control and Prevention, HHS.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Centers for Disease Control and Prevention (''CDC'') proposes to establish total inward leakage (TIL) requirements for half-mask air-purifying particulate respirators approved by the National Institute for Occupational Safety and Health (''NIOSH'') of CDC. The proposed new requirements specify TIL minimum performance requirements and testing to be conducted by NIOSH and respirator manufacturers to demonstrate that these respirators, when selected and used correctly, provide effective respiratory protection to intended users against toxic dusts, mists, fumes, fibers, and biological and infectious aerosols (*e.g.* influenza A(H5N1), severe acute respiratory syndrome (SARS) coronavirus, and *Mycobacterium tuberculosis*).

DATES: CDC invites comments on this proposed rule from interested parties. Comments must be received by December 29, 2009.

ADDRESSES: You may submit comments, identified by RIN: 0920–AA33, by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov*. Follow the instructions for submitting comments.
- *E-mail: niocindocket@cdc.gov*. Include (HHS INSERT RIN NUMBER) and ''42 CFR part 84'' in the subject line of the message.
- *Mail:* NIOSH Docket Office, Robert A. Taft Laboratories, MS–C34, 4676 Columbia Parkway, Cincinnati, OH 45226.

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

Docket: For access to the docket to read background documents or comments received, go to *http://www.regulations.gov*.

FOR FURTHER INFORMATION CONTACT: William Newcomb, NIOSH National Personal Protective Technology Laboratory (''NPPTL''), Pittsburgh, PA, (412) 386–4034 (this is not a toll-free number). Information requests can also be submitted by e-mail to *niocindocket@cdc.gov*.

SUPPLEMENTARY INFORMATION:

I. Public Participation

Interested persons or organizations are invited to participate in this rulemaking by submitting written views, arguments, recommendations, and data. Comments are invited on any topic related to this proposal.

Comments submitted by e-mail or mail should be addressed to the ''NIOSH Docket Officer,'' titled ''NIOSH Docket #137,'' and should identify the author(s), return address, and a phone number, in case clarification is needed. Comments can be submitted by e-mail to: *niocindocket@cdc.gov*. E-mail comments can be provided as e-mail text or as a Word or Word Perfect file attachment. Printed comments can be sent to the NIOSH Docket Office at the address above. All communications received on or before the closing date for comments will be fully considered by CDC.

All comments submitted will be available for examination in the rule docket (a publicly available repository of the documents associated with the rulemaking) both before and after the closing date for comments. A complete electronic docket containing all comments submitted will be available at: *http://www.cdc.gov/niosh/docket/NIOSHdocket0137.html* and comments will be available in writing by request. NIOSH includes all comments received without change in the docket, including any personal information provided.

II. Background

A. Introduction

Under 42 CFR part 84, ''Approval of Respiratory Protective Devices'' (''Part 84'') NIOSH approves respirators used by workers in mines and other workplaces for protection against hazardous atmospheres. The Mine Safety and Health Administration (''MSHA'') and the Occupational Safety and Health Administration (''OSHA'') require U.S. employers to supply NIOSH-approved respirators to their employees whenever the employer requires the use of respirators. In addition, MSHA co-approves with NIOSH all respirators used in mine emergencies and mine rescue.

Testing, quality control, and other requirements under Part 84 are intended to ensure that respirators supplied to U.S. workers provide effective protection when properly employed within a complete respiratory protection program, as specified under MSHA and OSHA regulations. NIOSH requirements governing approval of the type of respirators covered by this proposed rule are specified in 42 CFR part 84, principally under Subpart K—Non-Powered Air-Purifying Particulate Respirators. These were last updated in 1995 (60 *FR* 30336–30404). At that time, NIOSH proposed but ultimately omitted requirements for testing the performance of these respirators with respect to TIL [1] to allow for further research on the effectiveness of TIL testing methods.[2]

The performance of the facepiece-to-face seal and other potential sources of leakage for this type of respirator are important because these determine how much unfiltered contaminated air the worker might inhale. The facepiece-to-face seal leakage can be substantial in the case of a poorly fitting respirator.

Effective fit testing technology and procedures now exist to assure that respirators approved by NIOSH under Subpart K of Part 84 have adequately performing facepiece-to-face seals and sufficiently control TIL. The purpose of this rulemaking is to promulgate general requirements for such TIL testing and performance. The draft specific technical procedures to be applied under such requirements can be found at *http://www.cdc.gov/niosh/docket/NIOSHdocket0137.html*. When finalized, the procedure will be detailed with all other NIOSH respirator certification testing procedures on the NIOSH Web page at *http://www.cdc.gov/niosh/npptl/stps/respirator_testing.htm*.

B. Background and Significance

Employers rely upon NIOSH-approved respirators to protect their employees from airborne toxic contaminants and oxygen-deficient environments. More than 3.3 million private sector employees in the United States wear respirators for certain work tasks.

Workers depend on respirators to protect them from asphyxiation or airborne contaminants that are known or suspected to cause acute and chronic health effects, such as heavy metal poisoning, acid burns, chronic obstructive pulmonary disease, silicosis, neurological disorders, and cancer.

As the last line of protection for workers, respirators must be designed and manufactured to perform reliably and tested for compliance to a specified minimum level of performance. The worker might not be able to detect ineffective performance of the respirator prior to the toxic exposure, upon which it might be too late to avoid serious injury or death.

Respirator manufacturers and NIOSH have critical roles in assuring employers, other purchasers of respirators, and workers that their respirators will provide the protection that is implied by their NIOSH certification. This rulemaking, which has been identified as a priority among the policymaking needs of the NIOSH respirator certification program by respirator manufacturers, employers, and other stakeholders of the program, is intended to strengthen this assurance.

C. Need for Rulemaking

This rulemaking would establish TIL performance requirements and testing of half-mask, air-purifying particulate respirators currently approved under the requirements of Part 84 Subpart K—Non-Powered Air-Purifying Particulate Respirators. These respirators are used by two million U.S. workers: For example, they are used in health care settings by caregivers and staff to patients with tuberculosis and other respiratory infections; in foundries, chemical manufacturing, and other production facilities with potentially hazardous aerosol exposures such as metals, coal, plastics, fibers, nano materials, and silica; and at construction and landscaping sites where workers are exposed to wood, silica, and other dusts from the grounds and building materials. These respirators are also stockpiled in large caches for deployment to public safety, health care, and other service personnel in the advent of an influenza pandemic.

NIOSH evaluation of the TIL performance of these respirators would provide increased assurance to respirator purchasers and users that NIOSH-approved respirators can be expected to effectively protect the user against particulate contaminants, when properly donned and used. NIOSH has conducted benchmark testing of 101 respirator models currently on the market, using a testing regimen similar to that being proposed in this rulemaking, to assess their TIL performance. Approximately 30 percent of this class of respirators have facepiece seals that did not perform adequately to achieve a fit factor of 100 (limiting total inward leakage to no more than 1 percent), as specified by OSHA,[3] for substantial numbers of the human subjects donning them for

[1] TIL is the combination of contaminated air leaked through various potential sources including the facepiece-to-face seal, exhalation valves (if any), and gaskets (if any) and any contaminants that have penetrated the filter.

[2] The isoamyl acetate or American National Standards Institute (ANSI)/OSHA accepted fit tests.

[3] *See* 29 CFR 1910.134 (f)(7).

benchmark testing. This finding is supported by published research.[4 5]

There are three implications of this finding from benchmark testing, which define the need for this rulemaking. One, when an employer purchases one of these respirator models with poor TIL performance for use within a complete respirator program, as specified by OSHA and MSHA, fit-testing of the employees should reveal that a substantial proportion of the employees do not achieve an adequate fit. This presumably compels the employer to purchase other respirators and conduct additional fit-testing on employees, continuing such purchases and fit testing until respirators are identified, through trial and error, that provide all employees with adequately fitting respirators.

This process of identifying respirators that provide an adequate fit to each employee would be streamlined through NIOSH evaluation of TIL performance as proposed in this rulemaking, using panels of test subjects representative of intended users of a particular respirator model and size. The employee is more likely to achieve a good fit from a respirator make that has been demonstrated through testing to achieve a specified minimum level of performance in this respect.

The second implication applies to situations in which these poorly performing respirators are being used by employees and other individuals without the benefit of a complete respirator program that includes fit testing. A recent NIOSH/Bureau of Labor Statistics (BLS) survey of respirator use among U.S. workers found that 40 percent of employers are not selecting respirators for their employees based on fit testing.[6] Self-employed workers in industries such as construction may be even less likely to perform fit testing.

For these employee and worker populations, the poor fit might not be recognized, increasing the likelihood that substantial numbers of these respirator users are not being adequately protected from their hazardous exposures. While the only way to ensure that a particular respirator make and size performs adequately for a user is through fit testing of that user, NIOSH testing and evaluation of TIL performance would increase the likelihood that these workers who lack fit testing will be protected, by obtaining respirators that are demonstrated to generally provide a good fit to intended users when worn properly.

The third implication applies to the stockpiling of respirators for use in case of an influenza pandemic. During a disease outbreak, such respirators might be deployed without a respirator program and without fit testing. Currently, the selection of NIOSH approved respirators provides no assurance that stockpiled respirators are likely to provide adequate protection to the health care, public safety, and other personnel who might use them without a respirator program and fit testing. The availability of NIOSH certification with respect to TIL performance would increase the likelihood that such users would obtain an adequate fit and protection, even though it could not provide the same level of assurance as is obtained from fit testing of each individual for the selection of respirators.

In summary, revising Part 84 to incorporate minimum performance requirements governing TIL is a necessary step to ensure that NIOSH-approved half-mask air purifying particulate respirators have facepiece-to-face and other seals that perform adequately to provide effective protection to most intended users. While this certification testing will not substitute for individual fit testing, respirator training, and other components of a complete respiratory protection program critical to worker protection, it will substantially improve the current circumstances by approving only respirators that demonstrate the ability to meet minimum specified performance requirements and are likely to provide adequate protection to most intended users when properly fitted and worn.

D. Public Meetings for Discussion and for Comment

NIOSH held public meetings to discuss underlying issues and technical matters addressed in this proposed rule on August 25, 2004, at the Key Bridge Marriott, Arlington, VA, and June 26, 2007, at The Embassy Suites Pittsburgh International Airport, Coraopolis, Pennsylvania.[7] Official transcripts of the meetings, as well as public comments submitted subsequently, are available in Docket #36 from the NIOSH Docket Office at the address provided above.

One issue of concern raised in response to NIOSH presentations was that the NIOSH rule would prevent respirator manufacturers from producing models targeted to specific demographic subpopulations, such as women, for example. The current proposal would not impose any such limitation. NIOSH will construct test subject panels for the certification testing that represent the population targeted by the manufacturer, as described in the manufacturer's user instructions.

Another concern raised by commenters is that this rulemaking would shift responsibility for the fit achieved by employees from the employer, who is required to conduct fit testing under OSHA and MSHA regulations, to the respirator manufacturer. No such substitution is intended or effected by the rulemaking. As discussed above, NIOSH would require that manufacturers produce respirators that have effective face seals, such that they can be expected generally to fit intended users and control TIL adequately when the respirators are properly fit tested, donned, and used. This general assurance does not replace individual fit testing to be conducted by employers, which ensures that each individual employee obtains an effective fit, as required by OSHA and MSHA.

NIOSH already requires adequate TIL performance for other types of respirators under Part 84. NIOSH omitted such requirements for the category of respirator covered in this rulemaking only because of testing limitations that existed in 1995 when Part 84 was established.

NIOSH received concerns regarding the use of various testing technology and methods to evaluate TIL. The technology is identical to that in common use for measuring respirator fit and is accepted by OSHA.[8]

Comments were received questioning the representativeness of the test panel with respect to the population of respirator users. The test panel was developed by NIOSH to replace a panel developed decades ago by Los Alamos National Laboratory using military personnel. The new panel has been the subject of publications and multiple reviews, including a review by the

[4] Coffey C, Lawrence R, Campbell D, Zhuang Z, Calvert C, Jensen P. Fitting Characteristics of Eighteen N95 Filtering Facepiece Respirators. *JOEH.* 2004;1: 262–271.

[5] Lawrence R, Duling M, Calvert C, and Coffey C. Comparison of Performance of Three Different Types of Respiratory Protection Devices. *JOEH.* 2006;3:465–474.

[6] NIOSH/BLS [2003]. Respirator usage in private sector firms, 2001 (*PDF only* 1,118 KB (278 pages)). Cincinnati, OH: U.S. Department of Health and Human Services, Public Health Service, Centers for Disease Control and Prevention, National Institute for Occupational Safety and Health.

[7] Notice of these meetings was published in the **Federal Register** (FR69:133:42059) (FR72:102:29501–29502). NIOSH also sent a letter announcing the meetings to known stakeholders and posted it on the NIOSH Web page *http://www.cdc.gov/niosh/npptl.*

[8] 29 CFR 1910.134, Appendix A, Part I, C, 3.

Institute of Medicine.[9 10 11] It is documented in testing and agreed by reviewers that the proposed panel represents a substantial improvement over its predecessor panel and should be implemented.

Commenters also questioned the number of test subjects and the pass/fail criteria. NIOSH has changed the pass/fail criteria and the number of test subjects as a result of these comments. A full technical discussion of the statistical basis for the proposed standards described below is provided in a paper titled ''Statistical Basis for TIL Testing'' in the NIOSH Docket for this rulemaking posted at: *http://www.cdc.gov/niosh/docket/NIOSHdocket0137.html*. The maximum allowable leakage is now equivalent to the fit test criteria required by OSHA for this type of respirator.[12]

These concerns have been given consideration in the design of this proposed rule and will be considered further in the development of testing procedures to be implemented under a final rule. NIOSH encourages interested parties to submit any technical concerns along these lines, as well as policy concerns, in response to this proposed rule.

NIOSH will convene a public meeting to provide stakeholders an opportunity to comment orally on this rulemaking during the comment period. The meeting will be in the vicinity of Washington DC and will be announced in a separate notice in the **Federal Register**. This meeting will also be available through remote access capabilities. Participants will be able to simultaneously listen and view presentations over the Internet, as well as comment.

III. Summary of Proposed Rule

This proposed rule would establish new TIL requirements for half-mask air-purifying particulate respirators approved by NIOSH, or NIOSH and MSHA, under 42 CFR part 84—Approval of Respiratory Protective Devices. These provisions would be added to Subpart K. The following is a section-by-section summary which describes and explains the provisions of the rule. The public is invited to provide comment on any aspect of the proposed rule. The complete regulatory text for this proposed rule is provided in the last section of this notice. For the convenience of readers, the regulatory text presents the amended sections in their entirety, including the proposed new and revised paragraphs and those that would remain unrevised under the amended sections.

Subpart K

Section 84.175 Half-Mask Facepieces, Full Facepieces, Hoods, Helmets, and Mouthpieces; Fit and Total Inward Leakage (TIL); Minimum Requirements

This section includes a variety of general requirements governing the fit and functionality of the various designs of non-powered air-purifying particulate respirators. NIOSH proposes to amend this section to incorporate TIL standards and a general specification of testing requirements. Paragraphs in this section that are not discussed below are current provisions that NIOSH is not proposing to amend.

A. Half-Mask Respirators Designed for Specific Segments of the Population

Paragraph (a)(3) is new. It would allow applicants to seek approval for half-mask respirators designed to fit a specific segment of the population, such as ''women'' or persons within specific dimensional limits. Currently, respirators must be designed to fit the population broadly, either by providing one size that fits diverse facial shapes and sizes or by providing multiple sizes. It is advantageous to employers and other respirator purchasers to supply a respirator that fits the population broadly because it simplifies their selection and purchasing of such equipment. It also increases the likelihood that the majority of workers and other respirator users will obtain respirators that fit. However, in connection with public discussions regarding the concepts underlying TIL standards and testing, several respirator manufacturers have advocated that they have the option of producing respirators designed to fit particular subpopulations, presumably to more reliably achieve a fit for certain face shapes that might not obtain a good fit from generally-targeted designs. Furthermore, while NIOSH benchmark testing and other research have indicated that many respirators do not actually provide a good fit to substantial segments of the population, it is possible that some of these respirators are well designed to fit particular subpopulations.

NIOSH accepts the proposition that in some cases it might be effective to design respirators to fit specific subpopulations that share common facial characteristics, resulting in better TIL performance. Since this approach would rely on purchasers recognizing an appropriate match, NIOSH has specified that the membership of the subpopulation, as described, must be somehow identified. Thus, for example, sex is clear. However, it is unclear to NIOSH whether there are other demographic classifications or descriptors for subpopulations that could be both reliably interpreted by users and reliably determinative in terms of respirator fit. Users must be provided sufficient information to permit them to self-identify. They might not effectively self-identify to match a manufacturer's intentions if provided only vague general descriptions of intended facial shapes or characteristics.

A new paragraph (g) would require that any part of a respirator that would have to be removed to conduct a user seal check must be replaceable without disturbing the fit of the respirator. This is a current requirement for other types of respirators and is essential to assuring the validity of the seal check.

Paragraph (h) is also new. It would require the user instructions of a half-mask respirator to specify the intended users of the respirator, by facial size, if applicable, and by other descriptive information as might be necessary for respirators designed for specific subpopulations, as explained above. This information would be relied upon by purchasers and users and by NIOSH in conducting TIL testing, as discussed below.

B. Half-Mask Respirator TIL Testing Requirements

General Discussion

Subsection (i) is new. It proposes the general procedures, requirements, and performance standards for TIL of non-powered half-mask air-purifying particulate respirators. The standards have been designed statistically to identify and pass with high accuracy (greater than 90 percent probability) those respirators that provide adequate TIL performance to the large majority of intended users (in the range of 80 to 90 percent of intended users) while failing with near certainty (greater than 99 percent probability) those respirators that do not provide adequate TIL performance to a majority (50 percent or more) of intended users. Adequate TIL performance is a TIL value of 1.0,

[9] Zhuang Z, Bradtmiller B, and Shaffer R.E. New Respirator Fit Test Panels Representing the Current U.S. Civilian Workforce. Journal of Occupational and Environmental Hygiene 2007;4: 647–659.

[10] Zhuang Z, Groce D, Ahlers H, Iskander W, Landsittle D, Guffey S, Benson S, Viscusi D, Shaffer R. Correlation between Respirator Fit and Respirator Fit Test Panel Cells by Respirator Size. Journal of Occupational and Environmental Hygiene. 2008;5: 617–628.

[11] Institute of Medicine. Assessment of the NIOSH Head-and-Face Anthropometric Survey of U.S. Respirator Users. The National Academies Press, Washington, DC (2007).

[12] 29 CFR 1910.134(f)(7).

equivalent to a fit factor of 100, which is the level of performance for these respirators specified by OSHA.[13] The number of test subjects proposed for the testing has been limited to maintain reasonably modest testing costs for NIOSH and respirator manufacturers while achieving a representative cross-section of the intended user population and providing sufficient ''statistical power'' to evaluate TIL performance accurately. A full technical discussion of the statistical basis for the proposed standards described below is provided in a paper titled ''Statistical Basis for TIL Testing'' in the NIOSH Docket for this rulemaking posted at: *http://www.cdc.gov/niosh/docket/NIOSHdocket0137.html*. NIOSH requests public comment concerning the judgments inherent to these proposed standards, as well as comment on the supporting statistical analysis referenced here.

NIOSH invites public comment on the proposed standards specified in this subsection. There are several critical factors that the public should consider in providing such comments:

1. What percentage of the intended user population should be able to achieve adequate TIL performance for the respirator to be approved by NIOSH? NIOSH has proposed that 75 percent or higher should be able to achieve such performance. This performance level is based on the design and statistical considerations presented above in this General Discussion section; essentially, using this 75 percent testing parameter would provide strong assurance (90 percent probability) that testing identifies for approval respirators fitting the large majority—80 to 90 percent—of intended users, while rejecting with near certainty (99 percent probability) respirators that fit only a minority—less than 50 percent—of intended users.

2. As the percentage of the intended user population capable of achieving adequate TIL performance from a respirator declines, at what point, if any, should NIOSH set the limit to be nearly certain (e.g., 99 percent or higher probability) that the respirator would not be approved? NIOSH has proposed that a respirator should be rejected with near certainty if it does not provide adequate TIL performance to at least a majority (50 percent or greater) of intended users. NIOSH believes this is a reasonable standard for defining the performance of a poorly fitting respirator that should not be approved.

3. How many test subjects should be included in the testing, considering the fact that testing accuracy increases with the number of test subjects, but that the cost of testing also increases with the number of test subjects? Do the numbers of subjects proposed by NIOSH (15 to 35 test subjects, as specified under § 84.175(i)(4)) reflect an appropriate balance between limiting manufacturer testing costs and providing sufficiently accurate results? What level of testing cost is supportable, in the view of manufacturers? Would manufacturers prefer a higher numbers of test subjects and associated higher costs, to reduce further the likelihood that a respirator with adequate TIL performance is denied by chance?

Discussion of Specific Provisions

Paragraph (i)(1) specifies that NIOSH will apply solely the user instruction information describing the intended users of a respirator to select an appropriate panel of TIL test subjects. Thus, NIOSH will be interpreting the user instructions with the same limitations as a purchaser or intended user.

This provision would have no practical effect in the case of a respirator designed to fit the general population, either through one size that fits all users or a comprehensive set of differing sizes. In such a case, the respirator would be tested against the NIOSH testing panel, which respirator manufacturers can replicate in their pre-application TIL testing to ensure that their respirator is designed and manufactured to achieve an adequate fit on the testing panel to meet the NIOSH TIL standard. On the other hand, this provision limiting NIOSH to the information provided in the user instructions could be important in the case of a respirator designed for use by a specific subpopulation. As a consequence, if the applicant were to have selected test subjects for pre-application TIL testing using additional criteria or distinguishing factors not specified in the user instructions, it is possible the applicant would obtain a panel of test subjects substantially different from that selected by NIOSH for its TIL testing. A substantial difference in test panels could produce different testing results and potentially result in the failure of the respirator to pass the TIL performance standard.

Paragraph (i)(1) also specifies the number or minimum number of representative test subjects to be used in TIL testing; 35 for a respirator intended to fit the general population and a minimum of 15 for a respirator intended to fit one or more specific subpopulations. These numbers are proposed in combination with the performance standards specified in paragraph (i)(4) to provide a sufficiently accurate measure of a respirator's TIL performance for at least 75 percent of intended users while minimizing the chance of either approving a respirator that did not achieve adequate TIL performance for at least 50 percent of intended users or of disapproving a respirator that only by chance failed to achieve the TIL performance standard for at least 75 percent of intended users. A full technical discussion of the statistical bases of these standards is provided in a paper titled ''Statistical Basis for TIL Testing'' posted at: *http://www.cdc.gov/niosh/docket/NIOSHdocket0137.html*.

Paragraph (i)(2) specifies that test subjects will conduct a user seal check or other donning procedure prior to each test. This is appropriate practice for a worker donning this type of respirator, to ensure that it is positioned correctly on the face to provide an optimal facepiece-to-face seal.

Paragraph (i)(3) specifies that the TIL test will be administered to each test subject up to three times, terminating testing either when a test has produced a TIL value of 1.0 percent or less or after the third test, whichever occurs first. The TIL value of 1.0 percent is equivalent to a fit factor of 100, which is the minimum acceptable fit factor for half-mask respirators specified by OSHA under 29 CFR 1910.134 (f)(7). The limit of administering the test up to three times to achieve this performance standard is integral to the statistical basis establishing the accuracy of the TIL testing, as discussed above and in technical detail in the paper ''Statistical Basis for TIL Testing'' posted at: *http://www.cdc.gov/niosh/docket/NIOSHdocket0137.html*.

Paragraph (i)(4) provides the TIL performance standards for approval of these respirators, differing under clauses (i) and (ii) to account for the lower minimum number of test subjects (a minimum of 15 versus 35) that would be used to test a respirator intended to fit one or more specific subpopulations under clause (ii). Given the lower number of test subjects, a higher proportion of the test subjects (80 percent versus approximately 75%) would be required to achieve a TIL value of 1.0 percent or less for the respirator to be approved. This difference is statistically based in the decreasing reliability of an individual test as the total number of test subjects declines. It is discussed and illustrated in the paper ''Statistical Basis for TIL Testing'' posted at: *http://www.cdc.gov/niosh/docket/NIOSHdocket0137.html*. The proposed use of a minimum of 15 test subjects for respirators intended to

[13] *See* 29 CFR 1910.134(f)(7).

fit one or more subpopulations of users allows for the use of a larger number of test subjects for subpopulations that are more diverse and hence, require a more diverse panel of test subjects to provide sufficiently comprehensive representation of facial dimensions.

Paragraph (i)(5) specifies that the probe would be located halfway between the wearer's nose and mouth for TIL testing of the respirator. This specification is consistent with the technology used for such testing and is necessary to ensure a reproducible determination of TIL.

Paragraph (i)(6) specifies the use of sodium chloride (table salt) as the challenge aerosol for TIL testing and specifies a particle size range of 0.02 to 0.06 micrometers within a concentration range of 1,500 to 3,000 particles/cm^3. Sodium chloride is used because it is safe for the test subjects and has appropriate physical properties for the test. The particle size range represents the most penetrating particle sizes, producing an atmosphere that challenges the limits of the respirator's TIL performance. The concentration range allows for accurate measurement using the current technology available for TIL testing.

Paragraph (i)(7) specifies the sequence of exercises that comprise the TIL test. These are the standard, OSHA-required set of exercises to be used in fit-testing these respirators. They provide for realistic respirator use conditions that challenge the respirator's TIL performance through typical work movements, postures, grimaces that can disturb the facepiece-to-face seal, talking, and deep breathing to increase the negative pressure inside the facepiece.

Paragraph (i)(8) specifies that the test exercises will be performed using the OSHA protocol provisions specified at 29 CFR 1910.134 Appendix A, Part I.A.14(b). This protocol paragraph specifies the duration of each test exercise used in fit testing. Currently, OSHA requires each exercise be performed for one minute except for the grimace, which is performed for 15 seconds. By specifying this element of the OSHA protocol, NIOSH would ensure that NIOSH TIL testing remains consistent with OSHA fit testing requirements in this regard.

Paragraph (i)(9) specifies that the test subject will not adjust the facepiece position once the TIL test exercises begin, and that any such adjustment would void the test, requiring that it be repeated. This is current fit-testing practice and is required by OSHA under 29 CFR 1910.134 Appendix A, Part I.A.14(b). The intent of this requirement is to realistically reflect the practices and conditions of workers when wearing respirators. A worker typically would adjust the facepiece if he sensed a poor facepiece-to-face seal. However, a worker might not adjust the facepiece for many reasons, such as not sensing a poor facepiece-to-face seal, or being engaged in a task that occupies both hands. Moreover, the need to adjust the facepiece periodically after donning the respirator indicates an undesirable TIL performance characteristic. For example, the need to make such adjustments during a work task would constitute a hazard if safe work practice requires that the worker's hands and/or attention be fully engaged in the work task.

Paragraph (i)(10) specifies how TIL is determined. TIL results are expressed as the percentage quantity of the ambient concentration of sodium chloride measured inside the respirator. For example, if the ambient concentration were 1000 particles/cm^3 and the respirator reduced this concentration to 10 particles/cm^3, then the TIL would be expressed as 1.0 percent, because the concentration inside the respirator facepiece was reduced to 1.0 percent of the ambient level. This is equivalent to a fit factor of 100, which is the inverse of the TIL and is calculated as the ratio of the ambient concentration over the concentration inside the respirator facepiece.

Paragraph (i)(11) specifies design and performance attributes of the instrumentation to be used to take measurements of TIL. These include the use of a condensation nuclei counter, the ability to measure sodium chloride challenge aerosol in the specified size range of 0.02 to 0.06 micrometers, and during measurement, responding linearly to changes in the aerosol concentration, within plus or minus five percent, over the ambient concentration range of 70 to 3,000 particles/cm^3 and TIL $\leq$ 5.0 percent. These attributes are sufficient to meet the needs of TIL testing as proposed and to ensure that NIOSH and manufacturers use equivalent instrumentation.

Section 84.205 Facepiece Test; Minimum Requirements

This section specifies facepiece test requirements for chemical cartridge respirators. Some of these respirators are designed as half-mask, combination chemical cartridge/particulate filtering (i.e., air-purifying) respirators. For such combination respirators, NIOSH proposes applying the identical TIL test requirements as proposed under § 84.175 in this rulemaking for all half-mask air-purifying particulate respirators. These TIL test requirements would be in addition to the current facepiece test requirements already covered under this section for chemical cartridge respirators. Paragraphs in this section that are not discussed below are current provisions that NIOSH is not proposing to amend.

A. Non-Germane Technical Revisions to General Provisions of § 84.205

Paragraphs (c) and (d) would be revised, substituting the term ''user seal check'' for ''fit test'' to be consistent with current terminology in use.

Paragraph (d)(1) would be revised to reduce the specified ambient concentration of isoamyl acetate vapor in the testing chamber from 1,000 to 500 parts per million (ppm) for testing full facepieces, mouthpieces, hoods, and helmets. This represents current practice, which the NIOSH respirator certification program instituted when NIOSH lowered the IDLH (Immediately Dangerous to Life or Health concentration) for isoamyl acetate to 1,000 ppm.

B. Coverage of Combination Half-Mask Chemical Cartridge/Particulate Filtering Respirators by TIL Testing Requirements of § 84.175

A new paragraph (e) would be added to require TIL testing under the proposed provisions of § 84.175(i) for all combination half-mask chemical cartridge/particulate filtering respirators. The NIOSH respirator certification program currently conducts qualitative testing using isoamyl acetate vapor to evaluate the fit of chemical cartridge respirators under § 84.205, including these combination respirators. The proposed TIL testing would ensure that the particulate filtering protective capacity of these combination respirators is as effective as the single-purpose air-purifying respirators addressed by this rulemaking.

IV. Regulatory Assessment Requirements

A. Executive Order 12866

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the Agency must determine whether a regulatory action is ''significant'' and therefore subject to review by the Office of Management and Budget (OMB) and the requirements of the executive order. Under section 3(f), the order defines a ''significant regulatory action'' as an action that is likely to result in a rule (1) Having an annual effect on the economy of $100 million or more, or adversely and materially affecting a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities (also referred to as ''economically significant''); (2) creating serious inconsistency or otherwise interfering with an action taken or planned by another agency; (3) materially altering the budgetary impacts of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or (4) raising novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in this executive order.

This proposed rule is not considered economically significant, as defined in section 3(f)(1) of the executive order. However, this proposed rule is a ''significant regulatory action'' within the meaning of the executive order and has been reviewed by OMB.

For the leading U.S. respirator manufacturers who obtain approvals from NIOSH, likely to represent a majority share of the current market supply of NIOSH-approved products covered by this rulemaking, NIOSH benchmark testing indicates that the new TIL requirements can be met by current products without additional development or manufacturing costs. For those manufacturers whose products do not meet the proposed TIL testing standards, NIOSH has estimated design and retooling costs ranging from $55,000 to $200,000 per model or models of respirator with a unique facepiece, depending on the unit volume of production, the type of facepiece seal, and the degree of automation of the manufacturing operation. NIOSH invites comment from manufacturers on these estimates, all of which are based on expert opinion.

It is not possible to estimate the number of current approval holders whose products would not meet the proposed TIL requirements and who would redesign their products to seek new NIOSH approvals, incurring design and retooling costs. However, to the extent that some manufacturers may decide not to redesign products and seek new approvals, the proposed implementation schedule for the new requirements (*see* Section IV.J of this preamble) would provide other manufacturers sufficient time to increase production capacity and replace products exiting the NIOSH-approved respirator market. NIOSH invites comment from approval holders on their intent to seek new approvals under the proposed requirements.

All manufacturers intending to continue to hold NIOSH approvals for respirators covered by this rulemaking would incur additional costs for TIL testing. NIOSH estimates these costs would range from $8,500 to $12,000 per respirator approval, which would cover a respirator produced in multiple sizes and may also cover multiple respirator models employing the same respirator facepiece. The testing costs would vary based on the number of test subjects required. NIOSH anticipates applications for up to 500 approvals during the first two years of implementation of TIL requirements, when NIOSH expects the majority of requests for approval would be received. NIOSH estimates total testing and certification costs to manufacturers of up to $3.1 million annually for these two initial implementation years.[14] NIOSH anticipates TIL testing associated with routine submissions for new product approvals in subsequent years will be required for less than 15 percent of the NIOSH-approved product market annually, for estimated costs of $825,000 annually.[15]

NIOSH does not anticipate additional costs to consumers (*e.g.,* employers, self-employed workers) as a result of the proposed TIL requirements. The current NIOSH-approved products that NIOSH expects to pass the proposed requirements do not differ substantially in price from comparable products that are not expected to pass without modification.

NIOSH anticipates the TIL requirements will also result in substantial benefits, although NIOSH lacks information to estimate them quantitatively. Of greatest importance, substantial numbers of workers are more likely to derive the expected respiratory protection from hazardous particulate exposures as a result of using respirators with adequate TIL performance. As discussed in Section II.C. of this preamble, NIOSH benchmark testing and other research indicate that many respirators covered by this rulemaking do not perform well in preventing substantial inward leakage when tested against diverse facial types and sizes. Over 50 percent of workers and other respirator users do not have the benefit of individual fit testing, let alone a complete respiratory protection program. This suggests that substantial numbers of workers may receive improved protection as a result of instituting TIL testing for the certification of these respirators, increasing the likelihood that a worker without fit-testing or training might obtain adequate TIL performance. Such improved protection will result in reduced work-related disease and disability among the workforce, including such conditions as work-related silicosis, chronic obstructive pulmonary disease (COPD), asthma, and cancer, and biological and infectious diseases such as avian influenza, SARS,[16] and tuberculosis.[17] [18] Work-related COPD and asthma alone are estimated to cost $6.6 billion annually.[19] The costs of this rulemaking would be covered by the prevention of a small fraction of a percent of the occupational disease burden associated with workplace respiratory hazards.

In addition, as discussed in Section II.C. of this preamble, respirators that do not perform adequately in TIL testing would be expected to fail fit testing for employees among employers who conduct fit testing as required by OSHA. This is presumably causing the employers to purchase additional respirator models until all employees have respirators that fit adequately, incurring costs for the non-fitting respirators, for repeated respirator fit testing, and for lost employee work time consumed by the repetitive fit testing. NIOSH invites comments from employers regarding the current extent of such costs.

In summary, while NIOSH cannot estimate the total costs associated with this rulemaking, available information indicates these costs are modest and also suggests that they are likely to be considerably outweighed by economic benefits reaped by improved worker protection and the promotion of increased efficiency among employer respiratory protection programs.

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[14] This estimate assumes testing and certification of 250 units annually for two years at an average annual cost of $11,000 per unit for a panel of test subjects and $1,250 in other certification costs. About 30 percent of these other certification costs will be borne by the manufacturers irrespective of this proposed rulemaking as a result these products having a typical product life cycle of 5 to 10 years (see note 10 below).

[15] The product life cycle of these respirators is typically 5 to 10 years; meaning between 10 and 20 percent of 500 NIOSH-certified respirators could be expected to be redesigned annually on average. However, product redesigns would not necessarily involve redesign of the facepiece in such a way that would require TIL retesting.

[16] Eninger R, Honda T, Adhikari A, Heinonen-Tanski H, Reponen T, and Grinshpun S. Filter Performance of N99 and N95 Facepiece Respirators Against Viruses and Ultrafine Particles. *Ann. Occup. Hyg.* 2008;52(5):385–396.

[17] Willeke K, Qian Y, Donnelly J, Grinshpun S, Ulevicius V. Penetration of Airborne Microorganisms Through a Surgical Mask and a Dust/Mist Respirator. *American Industrial Hygiene Association Journal.* 1996;57(4):348–355.

[18] Qian Y, Willeke K, Grinshpun S, Donnelly J and Coffey C. Performance of N95 Respirators: Filtration Efficiency for Airborne Microbial and Inert Particles. *American Industrial Hygiene Association Journal.* 1998;59(2):128–132.

[19] Leigh JP, Romano P, Schenker MB, and Kreiss K. Costs of Occupational COPD and Asthma. *Chest.* 2002;121:264–272.

Through this rulemaking, NIOSH is inviting public comment from respirator manufacturers, employers, and others to provide greater specificity for NIOSH estimates of economic costs and benefits anticipated in association with the implementation of the proposed TIL requirements.

The proposed rule would not interfere with state, local, and tribal governments in the exercise of their governmental functions.

B. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA), 5 U.S.C. 601 *et seq.,* requires each agency to consider the potential impact of its regulations on small entities, including small businesses, small governmental units, and small not-for-profit organizations. The Department of Health and Human Services (''HHS'') certifies that this proposed rule would not have a significant economic impact on a substantial number of small entities within the meaning of the RFA.

The majority of respirator manufacturers producing half-mask air-purifying particulate respirators approved by NIOSH and covered by this rule are small businesses as defined under the Small Business Act (Pub. L. 85–536) for this industry sector (NAICS 339112—Medical Instruments and Equipment Manufacturers), employing fewer than 500 employees. For these manufacturers, the proposed rule would establish new TIL requirements applicable to respirators approved by NIOSH for use in potentially hazardous work atmospheres involving toxic, obstructive, and carcinogenic dusts, nanoparticles, and biological and potentially infectious aerosols. Workers don these respirators for protection in a wide variety of industrial sectors, such as mining, manufacturing, construction, and agriculture, and service sectors, such as health care, where medical, nursing, and custodial staff are exposed to biological and potentially infectious aerosols. These respirators are also being stockpiled and would be employed extensively by health care, public health, safety, and other first responders who would be engaged in the case of a pandemic influenza outbreak.

This rulemaking will result in additional costs for TIL testing and certification by NIOSH, for all respirator manufacturers intending to continue to hold NIOSH approvals for respirators covered by this rulemaking. As explained in Section IV.A of this preamble, NIOSH estimates the testing costs would range from $8,500 to $12,000 per respirator approval, which would include a respirator produced in multiple sizes and may also cover multiple respirator models employing the same respirator facepiece. The cost would vary depending on the number of test subjects required. NIOSH anticipates applications for up to 500 approvals during the first 2 years of implementation of TIL requirements, when the majority of requests for approval would be received. NIOSH estimates total testing and certification-related costs to manufacturers of $3.1 million annually for these 2 implementation years. NIOSH anticipates TIL testing associated with routine submissions for new product approvals in subsequent years will be required for less than 15 percent of the NIOSH-approved product market annually, for estimated costs of $825,000 annually.

These total testing and certification costs, from the initial 2-year implementation period, when annualized over an average 7.5-year product life-cycle, amount to less than $1.01 million annually. This is a small fraction of one percent of the annual revenues of respirator manufacturers, which totaled $1.7 billion in 2001 for all products and have grown extensively since.[20] Although respirator manufacturers produce a wide range of products beyond those covered by this rulemaking, half-mask air-purifying particulate respirators, including chemical gas mask/filtering respirators, represent the highest volume respirator sales and comprise a large component of total revenues.

After implementation, the routine annualized costs to manufacturers resulting from TIL testing associated with the redesign of products would be less than $141,000.[21]

As discussed in Section IV.A of this preamble, this rulemaking is not anticipated to result in any additional costs to small employers or self-employed workers and may result in lower costs. Based on NIOSH benchmark testing, respirators likely to represent a majority share of the current market supply are expected to pass the proposed TIL standards without modification, and these respirators are priced comparably to respirators that are not expected to pass as currently designed. Furthermore, the costs incurred by employers and by self-employed workers in selecting adequately fitting respirators through trial-and-error processes should be reduced as the implementation of this proposed rule curtails the supply of NIOSH-approved respirators with poor TIL performance.

NIOSH invites the public to provide more specific and current revenue data on the respirator market covered by this rulemaking.

For the reasons provided, a regulatory flexibility analysis, as provided for under RFA, is not required.

C. What Are the Paperwork and Other Information Collection Requirements (Subject to the Paperwork Reduction Act) Imposed Under This Rule?

The Paperwork Reduction Act is applicable to the data collection aspects of this rule. Under the Paperwork Reduction Act of 1995, a federal agency shall not conduct or sponsor a collection of information from ten or more persons other than Federal employees unless the agency has submitted a Standard Form 83, Clearance Request, and Notice of Action, to the Director of OMB, and the Director has approved the proposed collection of information. A person is not required to respond to a collection of information unless it displays a currently valid OMB control number.

NIOSH has obtained approval from OMB to collect information from respirator manufacturers under OMB Control No 0920–109 (Respiratory Protective Devices), which covers all information collection under 42 CFR part 84. This rulemaking would require NIOSH to collect new TIL testing information from manufacturers applying for approval of half-mask air-purifying particulate respirators covered by this rulemaking.

NIOSH estimates that the proposed TIL requirements will result in a minor increase in reporting burden to manufacturers. TIL testing would require the submission in the application package of one additional page of data describing the test results. These test results would already have been recorded by the applicant within the testing process so the only additional burden to the applicant would be any reformatting that might be necessary and the transfer of the results electronically to NIOSH. NIOSH anticipates this reporting, as part of the standard application package transmitted to NIOSH, would take no longer than 1 hour for completion; the current information collection approval pursuant to OMB Control No 0920–109 (Respiratory Protective Devices) estimates 86 hours per submission for each complete application under 42

[20] Frost and Sullivan Research Service; *http://www.frost.com/prod/servlet/report-brochure* published 30 March 2005.

[21] This assumes new products would be introduced for 15 percent of the product market annually, resulting in $865,000 of annual TIL testing costs. These are annualized over a 7.5 year period (the average life-cycle of these products.

CFR 84.11. Accordingly, in conjunction with this rulemaking, NIOSH will submit a request to OMB to amend its approval under OMB control No 0920–109 to collect this additional information.

D. Small Business Regulatory Enforcement Fairness Act

As required by Congress under the Small Business Regulatory Enforcement Fairness Act of 1996 (5 U.S.C. 801 *et seq.*), HHS would report to Congress the promulgation of a final rule, once it is developed, prior to its taking effect. The report would state that HHS has concluded that the rule is not a ''major rule'' because it is not likely to result in an annual effect on the economy of $100 million or more.

E. Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1531 *et seq.*) directs agencies to assess the effects of federal regulatory actions on State, local, and tribal governments, and the private sector ''other than to the extent that such regulations incorporate requirements specifically set forth in law.'' For purposes of the Unfunded Mandates Reform Act, this proposed rule does not include any federal mandate that may result in increased annual expenditures in excess of $100 million by state, local or tribal governments in the aggregate, or by the private sector.

F. Executive Order 12988 (Civil Justice)

This proposed rule has been drafted and reviewed in accordance with Executive Order 12988, Civil Justice Reform and will not unduly burden the federal court system. NIOSH has provided TIL requirements it would apply uniformly to all applications from manufacturers of half-mask air-purifying particulate respirators. This proposed rule has been reviewed carefully to eliminate drafting errors and ambiguities.

G. Executive Order 13132 (Federalism)

HHS has reviewed this proposed rule in accordance with Executive Order 13132 regarding federalism, and has determined that it does not have ''federalism implications.'' The proposed rule does 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.''

H. Executive Order 13045 (Protection of Children From Environmental Health Risks and Safety Risks)

In accordance with Executive Order 13045, HHS has evaluated the environmental health and safety effects of this proposed rule on children. HHS has determined that the proposed rule would have no effect on children.

I. Executive Order 13211 (Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use)

In accordance with Executive Order 13211, HHS has evaluated the effects of this proposed rule on energy supply, distribution, or use because it applies to the underground coal mining sector since coal mine operators are consumers of respirators. The proposed rule is unlikely to affect the cost of respirators used in coal mines and hence is not likely to have ''a significant adverse effect on the supply, distribution, or use of energy.'' Accordingly, this proposed rule does not constitute a ''significant energy action'' Under E.O. 13211 and requires no further Agency action or analysis.

J. Effective Date

NIOSH proposes that the final rule would take effect 30 days from publication in the **Federal Register** for all new respirator approval applications for half-mask air-purifying particulate respirators. Approval holders could continue to sell and ship respirators certified under current provisions subpart K as NIOSH/MSHA certified respirators throughout a transition period of three years from the effective date of the final rule and NIOSH would continue to consider modifications to such approvals for two years from the effective date. Continued use of distributed respirators is under the jurisdiction of OSHA and MSHA and would not be affected by this rule. NIOSH anticipates that OSHA and MSHA would permit continued use of those respirators since certifications will not be revoked for respirators sold and shipped by the approval holder during the three-year transition period. The authority for an approval holder to sell and distribute under a NIOSH certification any half-mask air-purifying particulate respirator certified under the current provisions of subpart K would expire at the end of the three-year period.

This 3-year transition period is proposed to ensure the timely replacement of respirators that demonstrate poor TIL performance while allowing an ample supply of respirators to remain available for use, since even a respirator with poor TIL performance may provide degrees of protection to different users. This timeframe would provide sufficient time for manufacturers to have respirators approved and manufactured in quantities to meet demand. According to NIOSH benchmark testing and other research, significant numbers of currently approved respirators of manufacturers with significant production capacity are likely to pass the proposed TIL testing and performance standards without modifications. On the other hand, NIOSH also seeks to ensure that total quantity of product supply remains sufficient during the transition period for current and potentially higher levels of demand. Such a demand spike could be anticipated if an influenza pandemic were to develop or increase in threat, instigating expanded stockpiling of respirators by health care, public health authorities, employers, workers, and the general public.

NIOSH encourages the public to comment on this proposed implementation schedule and any related issues. Some specific issues for comment include the following:

1. Do manufacturers believe they can meet the proposed TIL performance standards and testing requirements and provide adequate product supply to meet anticipated market demand within the proposed 3-year deadline?

2. Would any parties affected by this proposed rule incur an exceptional and unsupportable financial or other burden as a consequence of the proposed 3-year limit on the sale and distribution by approval holders of respirators certified under the current requirements (which omit TIL standards and testing)?

3. Would a different implementation schedule be better justified in terms of balancing the public health, practical, and economic benefits of removing from the market NIOSH-approved respirators with inadequate TIL performance against the public health, practical, and economic benefits of ensuring that an adequate supply of NIOSH-approved respirators remains constantly available? Please describe the advantages and disadvantages of extending or contracting the implementation schedule.

4. Are other factors that have not been identified by NIOSH important to deciding an appropriate implementation schedule?

List of Subjects in 42 CFR Part 84

Mine safety and health, Occupational safety and health, Personal protective equipment, Respirators.

Text of the Proposed Rule

For the reasons discussed in the preamble, NIOSH proposes to amend 42 CFR part 84 as follows:

PART 84—APPROVAL OF RESPIRATORY PROTECTIVE DEVICES

1. The authority citation for Part 84 continues to read as follows:

Authority: 29 U.S.C. 651 *et seq.*, and 657(g); 30 U.S.C. 3, 5, 7, 811, 842(h), 844.

Subpart K—Non-Powered Air-Purifying Particulate Respirators

2. Amend § 84.175 by revising the heading and adding new paragraphs (a)(3), and (g) through (i) to read as follows:

§ 84.175 Half-mask facepieces, full facepieces, hoods, helmets, and mouthpieces; fit and total inward leakage (TIL); minimum requirements.

(a) * * *

(3) Half-mask facepieces may be designed and constructed to fit only one or more defined subpopulations of the general population of respirator users, such as ''women'' or persons with faces within specific dimensional limits, provided that the membership of the subpopulation is readily discernable by the intended users.

* * * * *

(g) Any respirator part that must be removed by the respirator user to perform a user seal check shall be replaceable without special tools and without disturbing the facepiece seal.

(h) User instructions for half-mask respirators shall specify information necessary to identify the intended population of users:

(1) The applicant shall specify in the user instructions the face size or sizes that the respirator is intended to fit; pursuant to this requirement, one respirator may be intended to fit all face sizes; and

(2) If appropriate pursuant to paragraph (a)(3) of this section, then the applicant shall also specify in the user instructions any additional descriptions necessary to indicate the subpopulation(s) the respirator is intended to fit, such as sex, general facial characteristics, and/or precise facial measurements.

(i) Half-mask respirator TIL[1] testing requirements:

(1) NIOSH will employ specifications provided in user instructions, pursuant to paragraphs (h)(1) and (h)(2) of this section, to select representative test subjects for TIL testing, without further guidance from the manufacturer. NIOSH will conduct testing on 35 test subjects for a respirator of a single size or multiple sizes intended to fit the general population of respirator users, or on 15 or more test subjects for a respirator of a single size or multiple sizes designed to fit one or more specific subpopulations of respirator users.

(2) Immediately before each test, test subjects will conduct the user seal check or other donning procedures as specified in the user instructions.

(3) The TIL test shall be administered to each test subject up to three times, terminating testing either when a test has produced a TIL value of 1.0 percent or less or after the third test administered to the test subject, whichever occurs first.

(4) A TIL value of 1.0 percent or less shall be achieved by at least:

(i) 26 out of 35 test subjects for a respirator of a single size or of multiple sizes, designed to fit the general population of respirator users; or

(ii) 12 out of 15 test subjects (or 80 percent of test subjects if there are more than 15) for a respirator of a single size or multiple sizes designed to fit one or more specific subpopulations of respirator users.

(5) Each respirator used for testing will be probed approximately halfway between the wearer's nose and mouth.

(6) The TIL will be measured in the presence of a sodium chloride challenge aerosol with a concentration of 1,500 to 3,000 particles/cm^3 within the size range of 0.02 to 0.06 micrometers.

(7) The TIL will be measured while the following sequence of test exercises is conducted:

(i) Normal breathing;

(ii) Deep breathing;

(iii) Turn head side to side while pausing for two normal inhalations at each side;

(iv) Move head up and down while pausing for two normal inhalations in the head up position and in the head down position;

(v) Recite the Rainbow Passage;[2]

(vi) Reach for the floor and ceiling while pausing for two normal inhalations in the arms-up position and in the arms-down position;

(vii) Grimace (measurements during the grimace are not included in the TIL determination); and

(viii) Normal Breathing.

(8) Each test exercise will be performed using the OSHA protocol as specified at 29 CFR 1910.134 Appendix A, Part I.A.14.(b).

(9) The facepiece position will not be adjusted once the TIL test exercises begin; any adjustment performed will void the test and the test will be repeated in its entirety.

(10) The TIL will be determined by the ratio of the averages of the sodium chloride aerosol challenge concentration inside the facepiece to the challenge concentration outside the facepiece during the test; the TIL results will be expressed as a percentage: $TIL = [C_{in}/C_{out}] \times 100\%$.

(11) The instrumentation used to measure the concentration inside and outside the facepiece will:

(i) Utilize a condensation nuclei counter;

(ii) Measure only the concentrations of sodium chloride challenge aerosol in the approximate size range of 0.02 to 0.06 micrometers (mass median aerodynamic diameter); and

(iii) Respond linearly to changes in the aerosol concentration, within ±5 percent, over the ambient concentration range of 70 to 3,000 particles/cm^3 and TIL ≤ 5.0 percent, within the particle size range of 0.02 to 0.06 micrometers.

3. Amend § 84.205 by revising paragraphs (c), (d) and (e) to read as follows:

§ 84.205 Facepiece test; minimum requirements.

* * * * *

(c) Any chemical cartridge respirator part which must be removed to perform the facepiece or mouthpiece user seal check shall be replaceable without special tools and without disturbing facepiece or mouthpiece fit.

(d) The facepiece or mouthpiece user seal check using the positive or negative pressure recommended by the applicant and described in his instructions will be used before each test.

(1) Each wearer will enter a chamber containing 100 p.p.m. isoamyl acetate vapor for half-mask facepieces, and 500 p.p.m. for full facepieces, mouthpieces, hoods, and helmets.

(2) The facepiece or mouthpiece may be adjusted, if necessary, in the test chamber before starting the test.

(3) Each wearer will remain in the chamber for 8 minutes while performing the following activities:

(i) Two minutes, nodding and turning head;

(ii) Two minutes, calisthenic arm movements;

[1] TIL is the combination of contaminated air leaked through various potential sources including the facepiece-to-face seal, exhalation valves (if any), and gaskets (if any) and any contaminants that have penetrated the filter.

[2] The Rainbow Passage is a public domain text used in respirator testing to fully challenge the face seal to distortions that might arise from talking while wearing the respirator. It is widely available on the internet using any Internet search engine by entering ''Rainbow Passage.'' It is also available in the OSHA respirator rule at 29 CFR 1910.134 Appendix A, part I.A.14(a)(5).

(iii) Two minutes, running in place; and

(iv) Two minutes, pumping with a tire pump into a 28-liter (1 cubic-foot) container.

(4) Each wearer shall not detect the odor of isoamyl-acetate vapor during the test.

(e) In addition, any combination half-mask chemical cartridge/particulate filtering respirator shall meet the TIL testing requirements specified in paragraph (i) of § 84.175.

Dated: August 18, 2009.

Kathleen Sebelius,

Secretary, Department of Health and Human Services.

[FR Doc. E9–26008 Filed 10–29–09; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

42 CFR Part 440, 447 and 457

[CMS–2232–P2; CMS–2244–P2]

RIN 0938–AP72 and 0938–AP73

Medicaid Program: State Flexibility for Medicaid Benefit Packages and Premiums and Cost Sharing

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

ACTION: Proposed Rule.

SUMMARY: This document proposes to temporarily delay the effective date of the November 25, 2008 final rule entitled, ''Medicaid Program; Premiums and Cost Sharing'' and the December 3, 2008 final rule entitled, ''Medicaid Program; State Flexibility for Medicaid Benefit Packages.'' Upon the review and consideration of the new provisions of the American Recovery and Reinvestment Act of 2009, the Children's Health Insurance Program Reauthorization Act of 2009, and the public comments received during the reopened comment period, we believe that it is necessary to revise a substantial portion of the November 25, 2008 and the December 3, 2008 final rules. To allow time to make these revisions, the Department has determined that it needs several more months to revise the rule. Accordingly, we are asking for public comment on this proposal for delaying the effective date of the final rules until July 1, 2010.

DATES: To be assured consideration, comments must be received at one of the addresses provided below, no later than 5 p.m. on November 19, 2009.

ADDRESSES: In commenting, please refer to file code CMS–2244–P2 or CMS–2232–P2. Because of staff and resource limitations, we cannot accept comments by facsimile (FAX) transmission.

You may submit comments in one of four ways (please choose only one of the ways listed):

1. *Electronically.* You may submit electronic comments on this regulation to *http://www.regulations.gov.* Follow the instructions under the ''More Search Options'' tab.

2. *By regular mail.* You may mail written comments to the following address ONLY: Centers for Medicare & Medicaid Services, Department of Health and Human Services, *Attention:* CMS–2244–P2 or CMS–2232–P2, P.O. Box 8010, Baltimore, MD 21244–8010.

Please allow sufficient time for mailed comments to be received before the close of the comment period.

3. *By express or overnight mail.* You may send written comments to the following address ONLY: Centers for Medicare & Medicaid Services, Department of Health and Human Services, *Attention:* CMS–2244–P2 or CMS–2232–P2, Mail Stop C4–26–05, 7500 Security Boulevard, Baltimore, MD 21244–1850.

4. *By hand or courier.* If you prefer, you may deliver (by hand or courier) your written comments before the close of the comment period to either of the following addresses:

a. For delivery in Washington, DC—Centers for Medicare & Medicaid Services, Department of Health and Human Services, Room 445–G, Hubert H. Humphrey Building, 200 Independence Avenue, SW., Washington, DC 20201.

(Because access to the interior of the Hubert H. Humphrey Building is not readily available to persons without Federal government identification, commenters are encouraged to leave their comments in the CMS drop slots located in the main lobby of the building. A stamp-in clock is available for persons wishing to retain a proof of filing by stamping in and retaining an extra copy of the comments being filed.)

b. For delivery in Baltimore, MD—Centers for Medicare & Medicaid Services, Department of Health and Human Services, 7500 Security Boulevard, Baltimore, MD 21244–1850.

If you intend to deliver your comments to the Baltimore address, please call telephone number (410) 786–9994 in advance to schedule your arrival with one of our staff members.

Comments mailed to the addresses indicated as appropriate for hand or courier delivery may be delayed and received after the comment period.

FOR FURTHER INFORMATION CONTACT: Frances Crystal, (410) 786–1195 for State Flexibility for Medicaid Benefit Packages. Christine Gerhardt, (410) 786–0693 for Premiums and Cost Sharing.

SUPPLEMENTARY INFORMATION:

Inspection of Public Comments: All comments received before the close of the comment period are available for viewing by the public, including any personally identifiable or confidential business information that is included in a comment. We post all comments received before the close of the comment period on the following Web site as soon as possible after they have been received*: http://www.regulations.gov.* Follow the search instructions on that Web site to view public comments.

Comments received timely will also be available for public inspection as they are received, generally beginning approximately 3 weeks after publication of a document, at the headquarters of the Centers for Medicare & Medicaid Services, 7500 Security Boulevard, Baltimore, Maryland 21244, Monday through Friday of each week from 8:30 a.m. to 4 p.m. To schedule an appointment to view public comments, phone 1–800–743–3951.

I. Background

A. State Flexibility for Medicaid Benefit Packages

On December 3, 2008, we published a final rule in the **Federal Register** (73 FR 73694) entitled ''Medicaid Program; State Flexibility for Medicaid Benefit Packages.'' The December 2008 final rule implements provisions of section 6044 of the Deficit Reduction Act (DRA) of 2005, (Pub. L. 109–171), enacted on February 8, 2006, which amends the Social Security Act (the Act) by adding a new section 1937 related to the coverage of medical assistance under approved State plans. Section 1937 provides States increased flexibility under an approved State plan to provide covered medical assistance through enrollment of certain Medicaid recipients in benchmark or benchmark-equivalent benefit packages. The final rule set forth the requirements and limitations for this flexibility, after consideration of public comments on the February 22, 2008 proposed rule.

Subsequent to the publication of the December 3, 2008 final rule, we published an interim final rule with comment period in the **Federal Register** on February 2, 2009 (74 FR 5808) to temporarily delay for 60 days the effective date of the December 3, 2008 final rule entitled, ''Medicaid Program; State Flexibility for Medicaid Benefit Packages.'' The interim final rule also reopened the comment period on the policies set out in the December 3, 2008 final rule. We received 9 public comments in response to the February 2, 2009 interim final rule.

On February 4, 2009, the Children's Health Insurance Program Reauthorization Act (CHIPRA) of 2009 (Pub. L. 111–3) was enacted. Certain provisions of the CHIPRA affect current regulations regarding State Flexibility for Medicaid Benefit Packages, including the December 3, 2008 final rule. Specifically, section 611(a)(1)(C) and section 611(a)(3) of CHIPRA amends section 1937 of the Act, to require States to assure that children under the age of 21, rather than those under 19 as specified in the DRA of 2005, who are included in benchmark or benchmark-equivalent plans, have access to the Early Periodic Screening, Diagnosis, and Treatment (EPSDT) services. EPSDT services may be provided through a benchmark or benchmark-equivalent plan or as an additional benefit to those plans.

Section 611(a)(1)(A)(i) of CHIPRA amends section 1937 of the Act by changing the language ''Notwithstanding any other provision of this title * * *'' to read ''Notwithstanding section 1902(a)(1)(relating to statewideness), section 1902(a)(10)(B) (relating to comparability), and any other provision of this title which would be directly contrary to the authority * * *''

On April 3, 2009, we published a second final rule (74 FR 15221) in the **Federal Register** further delaying implementation of the December 3, 2008 rule until December 31, 2009 and reopening the comment period to permit additional comments on the policies set forth in the December 3, 2008 final rule and the statutory changes contained in CHIPRA. This second delay specifically requested comments on the provisions of the CHIPRA enacted on February 4, 2009, which corrected language in the DRA as if these amendments were included in the DRA, and subsequently amended section 1937 of the Act, ''State Flexibility for Medicaid Benefit Packages.'' We received 7 timely items of correspondence in response to the April 3, 2009 interim final rule.

B. Premiums and Cost Sharing

On November 25, 2008, we published a final rule entitled, ''Medicaid Program; Premiums and Cost Sharing'' in the **Federal Register** (73 FR 71828) to implement and interpret the provisions of the DRA and the Tax Relief and Health Care Act of 2006 (TRHCA). The DRA was amended by TRHCA to include limitations on cost sharing for individuals with family incomes at or below 100 percent of the Federal poverty line. The DRA also provided State Medicaid agencies with increased flexibility to impose premium and cost sharing requirements on certain Medicaid recipients. The DRA provisions also specifically addressed cost sharing for non-preferred drugs and non-emergency care furnished in a hospital emergency department. The November 25, 2008 final rule integrated into CMS regulations the statutory flexibility to impose premiums and cost sharing that was added by the DRA. In addition, in the November 25, 2008 final rule, we responded to public comments on the February 22, 2008 proposed rule.

Subsequent to the publication of the November 25, 2008 final rule, we published a final rule in the **Federal Register** on January 27, 2009 (74 FR 4888) that temporarily delayed for 60 days the effective date of the November 25, 2008 final rule. The final rule also reopened the comment period on the policies set out in the November 25, 2008 final rule.

On February 17, 2009, the American Recovery and Reinvestment Act of 2009 (the Recovery Act) was enacted subsequent to the publication of the January 27, 2009 delay of effective date. Certain provisions of the Recovery Act affect current regulations regarding premiums and cost sharing. Specifically, under the Recovery Act, effective July 1, 2009, Medicaid and CHIP programs are prohibited from imposing premiums or other cost sharing payments on Indians who are provided services or items covered under the Medicaid State plan by Indian Health providers or through referral under contract health services. Similarly, payments to Indian Health providers or to a health care provider through referral under contract health services for Medicaid services or items furnished to Indians cannot be reduced by the amount of any enrollment fee, premium, or cost sharing that otherwise would be due from the Indians.

On March 27, 2009, we published a second final rule in the **Federal Register** (74 FR 13346) that further delayed the effective date of the November 25, 2008 final rule until December 31, 2009. The final rule reopened the comment period to give the public an additional opportunity to submit comments on the policy set forth in the final rule as well as the provisions of the Recovery Act. Comments were specifically solicited on the effect of certain provisions of the Recovery Act related to the exclusion of Indians from payments of premiums and cost sharing.

II. Provisions of the Proposed Regulation

We are proposing to delay the effective date of the November 25, 2008 and December 3, 2008 final rules (collectively, ''the 2008 final rules'') until July 1, 2010. Upon review and consideration of the new provisions of CHIPRA, the Recovery Act, and the public comments received during the reopened comment periods, we believe that it is necessary to revise a substantial portion of these final rules. To allow time to make these revisions, the Department has determined that it needs several more months to revise the rule. Accordingly, we are asking for public comment on this proposal for delaying the effective date of the final rules until July 1, 2010.

The comments received during the reopened comment period were complex and presented numerous policy issues, which require extensive consultation, review, and analysis. Additionally, because both CHIPRA and the Recovery Act contain provisions that impact the American Indian and Alaska Native community, the development of the final rules requires collaboration with other HHS agencies and the Tribal governments.

Therefore, we are proposing to further delay the effective date of the 2008 final rules until July 1, 2010. We anticipate that this time period would allow sufficient time for CMS to further consider public comments, analyze the impact of the revisions on affected stakeholders, and develop appropriate revisions to the regulations. We note that, although we are proposing to delay the effective date of the 2008 final rules jointly because it is more efficient to do so, revisions to the 2008 final rules will be published as two separate revised final rules.

III. Response to Comments

Because of the large number of public comments we normally receive on **Federal Register** documents, we are not able to acknowledge or respond to them individually. We will consider all comments we receive by the date and time specified in the **DATES** section of this preamble, and, when we proceed with a subsequent document, we will respond to the comments in the preamble to that document.

(Catalog of Federal Domestic Assistance Program No. 93.778, Medical Assistance Program.)

Dated: October 22, 2009.

Charlene Frizzera,

Acting Administrator, Centers for Medicare & Medicaid Services.

Approved: October 27, 2009.

Kathleen Sebelius,

Secretary.

[FR Doc. E9–26297 Filed 10–29–09; 8:45 am]

BILLING CODE 4120–01–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

46 CFR Part 401

[Docket No. USCG–2009–0883]

RIN 1625–AB39

Great Lakes Pilotage Rates—2010 Annual Review and Adjustment

AGENCY: Coast Guard, DHS.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Coast Guard proposes to update the rates for pilotage on the Great Lakes by 5.07% to generate sufficient revenue to cover allowable expenses, target pilot compensation, and return on investment. The proposed update reflects an August 1, 2010 increase in benchmark contractual wages and benefits and an adjustment for inflation. This rulemaking promotes the Coast Guard strategic goal of maritime safety.

DATES: Comments and related material must reach the Docket Management Facility on or before November 30, 2009.

ADDRESSES: You may submit comments identified by Coast Guard docket number USCG–2009–0883 to the Docket Management Facility at the U.S. Department of Transportation. To avoid duplication, please use only one of the following methods:

(1) *Federal eRulemaking Portal: http://www.regulations.gov.*

(2) *Fax:* 202–493–2251.

(3) *Mail:* Docket Management Facility (M–30), U.S. Department of Transportation, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590–0001.

(4) *Hand delivery:* Same as mail address above, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The telephone number is 202–366–9329.

FOR FURTHER INFORMATION CONTACT: For questions on this proposed rule, call Mr. Paul M. Wasserman, Chief, Great Lakes Pilotage Branch, Commandant (CG–54122), U.S. Coast Guard, at 202–372–1535, by fax 202–372–1929, or by e-mail at *Paul.M.Wasserman@uscg.mil.* If you have questions on viewing or submitting material to the docket, call Renee V. Wright, Program Manager, Docket Operations, telephone 202–366–9826.

SUPPLEMENTARY INFORMATION:

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I. Public Participation and Request for Comments

We encourage you to participate in this rulemaking by submitting comments and related materials. All comments received will be posted, without change, to *http://www.regulations.gov* and will include any personal information you have provided. We have an agreement with the Department of Transportation to use the Docket Management Facility.

A. Submitting Comments

If you submit a comment, please include the docket number for this rulemaking, (USCG–2009–0883), indicate the specific section of this document to which each comment applies, and provide a reason for each suggestion or recommendation. You may submit your comments and material online or by fax, mail, or hand delivery, but please use only one of these means. We recommend that you include your name and a mailing address, an e-mail address, or a phone number in the body of your document so that we can contact you if we have questions regarding your submission.

To submit your comment online, go to *http://www.regulations.gov,* click on the ''submit a comment'' box, which will then become highlighted in blue. In the ''Document Type'' drop down menu select ''Proposed Rule'' and insert ''USCG–2009–0883'' in the ''Keyword'' box. Click ''Search'' then click on the balloon shape in the ''Actions'' column. If you submit your comments by mail or hand delivery, submit them in an unbound format, no larger than 8½ by 11 inches, suitable for copying and electronic filing. If you submit comments by mail and would like to know that they reached the Facility, please enclose a stamped, self-addressed postcard or envelope.

We will consider all comments and material received during the comment period and may change this proposed rule based on your comments.

B. Viewing Comments and Documents

To view comments, as well as documents mentioned in this preamble as being available in the docket, go to *http://www.regulations.gov,* click on the ''read comments'' box, which will then become highlighted in blue. In the ''Keyword'' box insert ''USCG–2009–0883'' and click ''Search.'' Click the ''Open Docket Folder'' in the ''Actions'' column. If you do not have access to the internet, you may view the docket online by visiting the Docket Management Facility in Room W12–140 on the ground floor of the Department of Transportation West Building, 1200 New Jersey Avenue, SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. We have an agreement with the Department of Transportation to use the Docket Management Facility.

C. Privacy Act

Anyone can 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 a Privacy Act system of records notice regarding our public dockets in the January 17, 2008 issue of the **Federal Register** (73 FR 3316).

D. Public Meeting

We do not plan to hold a public meeting. But you may submit a request for one to the Docket Management Facility at the address under **ADDRESSES** explaining why one would be beneficial. If we determine that one would aid this rulemaking, we will hold one at a time and place announced by a later notice in the **Federal Register**.

II. Abbreviations

AMOU American Maritime Officers Union
MISLE Marine Information for Safety and Law Enforcement
NAICS North American Industry Classification System

NEPA National Environmental Policy Act of 1969
NPRM Notice of Proposed Rulemaking
NVMC National Vessel Movement Center
OMB Office of Management and Budget

III. Background and Purpose

This notice of proposed rulemaking (NPRM) is issued pursuant to Coast Guard regulations in 46 CFR Parts 401–404. Those regulations implement the Great Lakes Pilotage Act of 1960, 46 U.S.C. Chapter 93, which requires foreign-flag vessels and U.S.-flag vessels engaged in foreign trade to use federally registered Great Lakes pilots while transiting the St. Lawrence Seaway and the Great Lakes system, and which requires the Secretary of Homeland Security to ''prescribe by regulation rates and charges for pilotage services, giving consideration to the public interest and the costs of providing the services.'' 46 U.S.C. 9303(f).

The U.S. waters of the Great Lakes and the St. Lawrence Seaway are divided into three pilotage Districts. Pilotage in each District is provided by an association certified by the Coast Guard Director of Great Lakes Pilotage to operate a pilotage pool. It is important to note that, while the Coast Guard sets rates, it does not control the actual compensation that pilots receive. This is determined by each of the three District associations, which use different compensation practices.

District One, consisting of Areas 1 and 2, includes all U.S. waters of the St. Lawrence River and Lake Ontario. District Two, consisting of Areas 4 and 5, includes all U.S. waters of Lake Erie, the Detroit River, Lake St. Clair, and the St. Clair River. District Three, consisting of Areas 6, 7, and 8, includes all U.S. waters of the St. Mary's River, Sault Ste. Marie Locks, and Lakes Michigan, Huron, and Superior. Area 3 is the Welland Canal, which is serviced exclusively by the Canadian Great Lakes Pilotage Authority and, accordingly, is not included in the U.S. rate structure. Areas 1, 5, and 7 have been designated by Presidential Proclamation, pursuant to the Great Lakes Pilotage Act of 1960, to be waters in which pilots must at all times be fully engaged in the navigation of vessels in their charge. Areas 2, 4, 6, and 8 have not been so designated because they are open bodies of water. Under the Great Lakes Pilotage Act of 1960, pilots assigned to vessels in these areas are only required to ''be on board and available to direct the navigation of the vessel at the discretion of and subject to the customary authority of the master.'' 46 U.S.C. 9302(a)(1)(B).

The Coast Guard pilotage regulations require annual reviews of pilotage rates and the setting of new rates at least once every five years, or sooner, if annual reviews show a need. 46 CFR 404.1. To assist in calculating pilotage rates, the pilotage associations are required to submit to the Coast Guard annual financial statements prepared by certified public accounting firms. In addition, every fifth year, in connection with the mandatory rate adjustment, the Coast Guard contracts with an independent accounting firm to conduct a full audit of the accounts and records of the pilotage associations and prepare and submit financial reports relevant to the ratemaking process. In those years when a full ratemaking is conducted, the Coast Guard generates the pilotage rates using Appendix A to 46 CFR part 404. Between the five-year full ratemaking intervals, the Coast Guard annually reviews the pilotage rates using Appendix C to Part 404, and adjusts rates when deemed appropriate. Terms and formulas used in Appendix A and Appendix C are defined in Appendix B to Part 404.

The last full ratemaking using the Appendix A methodology was published on April 3, 2006 (71 FR 16501). Since then, rates have been reviewed under Appendix C and adjusted annually: 2007 (72 FR 53158, Sep. 18, 2007); 2008 (interim rule 73 FR 15092, Mar. 21, 2008; final rule 74 FR 220, Jan. 5, 2009); 2009 (74 FR 18669, Jul. 21, 2009). The present rulemaking proposes a rate adjustment for the 2010 shipping season, based on an Appendix C review. At the conclusion of this ratemaking cycle and during the latter portion of the 2010 navigation season, we anticipate publishing an NPRM proposing a rate adjustment based upon an Appendix A 5-year review and full audit of the pilot association books and records.

IV. Discussion of the Proposed Rule

The pilotage regulations require that pilotage rates be reviewed annually. If the annual review shows that pilotage rates are within a reasonable range of the base target pilot compensation set in the previous ratemaking, no adjustment to the rates will be initiated. However, if the annual review indicates that an adjustment is necessary, then the Coast Guard will establish new pilotage rates pursuant to 46 CFR 404.10.

A. Proposed Pilotage Rate Changes—Summarized

The Appendix C to 46 CFR 404 ratemaking methodology is intended for use during the years between Appendix A full ratemaking reviews and adjustments. This section summarizes the rate changes proposed for 2010, and then discusses in detail how the proposed changes were calculated under Appendix C.

We are proposing an increase of 5.07% across all Districts over the last pilotage rate adjustment. This reflects an August 1, 2010, increase in benchmark contractual wages and benefits and an inflation adjustment. This rate increase would not go into effect until August 1, 2010. Actual rate increases vary by Area, and are summarized in Table 1.

TABLE 1—2010 AREA RATE CHANGES

If pilotage service is required in:	Then the proposed percentage increases over the current rate is:
Area 1 (Designated waters)	4.65
Area 2 (Undesignated waters)	5.33
Area 4 (Undesignated waters)	5.47
Area 5 (Designated waters)	4.96
Area 6 (Undesignated waters)	5.27
Area 7 (Designated waters)	4.73
Area 8 (Undesignated waters)	5.17
Overall Rate Change (percentage change in overall prospective unit costs/base unit costs; see Table 18)	5.07

Rates for cancellation, delay, or interruption in rendering services (46 CFR 401.420), and basic rates and charges for carrying a U.S. pilot beyond the normal change point, or for boarding at other than the normal boarding point (46 CFR 401.428), have been increased by 5.07% in all Areas.

B. Calculating the Rate Adjustment

The Appendix C ratemaking calculation involves eight steps:

Step 1: Calculate the total economic costs for the base period (*i.e.* pilot compensation expense plus all other recognized expenses plus the return element) and divide by the total bridge hours used in setting the base period rates;

Step 2: Calculate the ''expense multiplier,'' the ratio of other expenses and the return element to pilot compensation for the base period;

Step 3: Calculate an annual ''projection of target pilot compensation'' using the same procedures found in Step 2 of Appendix A;

Step 4: Increase the projected pilot compensation in Step 3 by the expense multiplier in Step 2;

Step 5: Adjust the result in Step 4, as required, for inflation or deflation;

Step 6: Divide the result in Step 5 by projected bridge hours to determine total unit costs;

Step 7: Divide prospective unit costs in Step 6 by the base period unit costs in Step 1; and

Step 8: Adjust the base period rates by the percentage changes in unit cost in Step 7.

The base data used to calculate each of the eight steps comes from the 2009 Appendix C review. The Coast Guard also used the most recent union contracts between the American Maritime Officers Union (AMOU) and vessel owners and operators on the Great Lakes to determine target pilot compensation. Bridge hour projections for the 2010 season have been obtained from historical data, pilots, and industry. All documents and records used in this rate calculation have been placed in the public docket for this rulemaking and are available for review at the addresses listed under **ADDRESSES**.

Some values may not total exactly due to format rounding for presentation in charts and explanations in this section. The rounding does not affect the integrity or truncate the real value of all calculations in the ratemaking methodology described below. Also, please note that in previous rulemakings we calculated an expense multiplier for each District. This was unnecessary because Appendix C calculations are based on Area figures, not District figures. District figures, where they are shown in the following tables, now reflect only the arithmetical totals for each of the District's Areas.

Step 1: Calculate the total economic cost for the base period. In this step, for each Area, we add the total cost of target pilot compensation, all other recognized expenses, and the return element (net income plus interest). We divide this sum by the total bridge hours for each Area. The result is the cost in each Area of providing pilotage service per bridge hour for the base period. Tables 2 through 4 summarize the Step 1 calculations:

TABLE 2—TOTAL ECONOMIC COST FOR BASE PERIOD (2009), AREAS IN DISTRICT ONE

	Area 1 St. Lawrence River	Area 2 Lake Ontario	Total* District One
Base operating expense (less base return element)	$538,155	$547,489	$1,085,644
Base target pilot compensation	+ $1,617,955	+ $981,589	+ $2,599,544
Base return element	+ $10,763	+ $16,425	+ $27,188
Subtotal*	= $2,166,873	= $1,545,503	= $3,712,376
Base bridge hours	÷ 5,203	÷ 5,650	÷ 10,853
Base cost per bridge hour	= $416.47	= $273.54	= $342.06

*As explained in the text preceding Step 1, District totals have been expressed differently from previous rulemakings. This accounts for slight differences between the District totals shown in Table 16 of the 2009 final rule and the District totals shown in this table.

TABLE 3—TOTAL ECONOMIC COST FOR BASE PERIOD (2009), AREAS IN DISTRICT TWO

	Area 4 Lake Erie	Area 5 Southeast Shoal to Port Huron, MI	Total* District Two
Base operating expense	$502,087	$789,202	$1,291,289
Base target pilot compensation	+ $785,271	+ $1,617,955	+ $2,403,226
Base return element	+ $25,104	+ $31,568	+ $56,672
Subtotal	= $1,312,463	= $2,438,725	= $3,751,188
Base bridge hours	÷ 7,320	÷ 5,097	÷ 12,417
Base cost per bridge hour	= $179.30	= $478.46	= $302.10

*See footnote to Table 2.

TABLE 4—TOTAL ECONOMIC COST FOR BASE PERIOD (2009), AREAS IN DISTRICT THREE

	Area 6 Lakes Huron and Michigan	Area 7 St. Mary's River	Area 8 Lake Superior	Total* District Three
Base operating expense	$814,358	$398,461	$641,580	$1,854,399
Base target pilot compensation	+ $1,570,542	+ $1,078,637	+ $1,374,224	+ $4,023,403
Base return element	+ $32,574	+ $11,954	+ $19,247	+ $63,776
Subtotal	= $2,417,474	= $1,489,052	= $2,035,052	= $5,941,578

TABLE 4—TOTAL ECONOMIC COST FOR BASE PERIOD (2009), AREAS IN DISTRICT THREE—Continued

	Area 6 Lakes Huron and Michigan	Area 7 St. Mary's River	Area 8 Lake Superior	Total* District Three
Base bridge hours	÷ 13,406	÷ 3,259	÷ 11,630	÷ 28,295
Base cost per bridge hour	= $180.33	= $456.90	= $174.98	= $209.99

*See footnote to Table 2.

Step 2. Calculate the expense multiplier. In this step, for each Area, we add the base operating expense and the base return element. Then, we divide the sum by the base target pilot compensation to get the expense multiplier for each Area. Tables 5 through 7 show the Step 2 calculations.

TABLE 5—EXPENSE MULTIPLIER, AREAS IN DISTRICT ONE

	Area 1 St. Lawrence River	Area 2 Lake Ontario	Total District One
Base operating expense	$538,155	$547,489	$1,085,644
Base return element	+ $10,763	+ $16,425	+ $27,188
Subtotal	= $548,918	= $563,914	= $1,112,832
Base target pilot compensation	÷ $1,617,955	÷ $981,589	$2,599,544
Expense multiplier	0.33927	0.57449	n/a

TABLE 6—EXPENSE MULTIPLIER, AREAS IN DISTRICT TWO

	Area 4 Lake Erie	Area 5 Southeast Shoal to Port Huron, MI	Total District Two
Base operating expense	$502,087	$789,202	$1,291,289
Base return element	+ $25,104	+ $31,568	+ $56,672
Subtotal	= $527,192	= $820,770	= $1,347,962
Base target pilot compensation	÷ $785,271	÷ $1,617,955	$2,403,226
Expense multiplier	0.67135	0.50729	n/a

TABLE 7—EXPENSE MULTIPLIER, AREAS IN DISTRICT THREE

	Area 6 Lakes Huron and Michigan	Area 7 St. Mary's River	Area 8 Lake Superior	Total District Three
Base operating Expense	$814,358	$398,461	$641,580	$1,854,399
Base return element	+ $32,574	+ $11,954	+ $19,247	+ $63,776
Subtotal	= $846,932	= $410,415	= $660,828	= $1,918,175
Base target pilot compensation	÷ $1,570,542	÷ $1,078,637	÷ $1,374,224	$4,023,403
Expense multiplier	0.53926	0.38049	0.48087	n/a

Step 3. Calculate annual projection of target pilot compensation. In this step, we determine the new target rate of compensation and the new number of pilots needed in each pilotage Area, to determine the new target pilot compensation for each Area.

(a) Determine new target rate of compensation. Target pilot compensation is based on the average annual compensation of first mates and masters on U.S. Great Lakes vessels. For pilots in undesignated waters, we approximate the first mates' compensation and, in designated waters, we approximate the master's compensation (first mates' wages multiplied by 150% plus benefits). To determine first mates' and masters' average annual compensation, we use data from the most recent AMOU contracts with the U.S. companies engaged in Great Lakes shipping. Where different AMOU agreements apply to different companies, we apportion the compensation provided by each agreement according to the percentage of tonnage represented by companies under each agreement.

As of May 2009, there are two current AMOU contracts, which we designate Agreement A and Agreement B. Agreement A applies to vessels operated by Key Lakes, Inc., and Agreement B applies to all vessels operated by American Steamship Co. and Mittal Steel USA, Inc.

Both Agreement A and Agreement B provide for a 3% wage increase effective August 1, 2010. Under Agreement A, the daily wage rate will be increased from $262.73 to $270.61. Under Agreement B, the daily wage rate will be increased from $323.86 to $333.57.

To calculate monthly wages, we apply Agreement A and Agreement B monthly multipliers of 54.5 and 49.5, respectively, to the daily rate.

Agreement A's 54.5 multiplier represents 30.5 average working days, 15.5 vacation days, 4 days for four weekends, 3 bonus days, and 1.5 holidays. Agreement B's 49.5 multiplier represents 30.5 average working days, 16 vacation days, and 3 bonus days.

To calculate average annual compensation, we multiply monthly figures by 9 months, the length of the Great Lakes shipping season.

Table 8 shows new wage calculations based on Agreements A and B effective August 1, 2010.

TABLE 8—WAGES

Monthly component	Pilots on undesignated waters	Pilots on designated waters (undesignated × 150%)
AGREEMENT A:		
$270.61 daily rate × 54.5 days	$14,748	$22,123
AGREEMENT A:		
Monthly total × 9 months = total wages	$132,735	$199,103
AGREEMENT B:		
$333.57 daily rate × 49.5 days	$16,512	$24,768
AGREEMENT B:		
Monthly total × 9 months = total wages	$148,608	$222,912

Both Agreements A and B include a health benefits contribution rate of $88.76 effective August 1, 2010. Agreement A includes a pension plan contribution rate of $33.35 per man-day. Agreement B includes a pension plan contribution rate of $43.55 per man-day. Both Agreements A and B provide a 401K employer matching rate, 5% of the wage rate. Neither Agreement A nor Agreement B includes a clerical contribution that appeared in earlier contracts. Per the AMOU, the multiplier used to calculate monthly benefits is 45.5 days.

Table 9 shows new benefit calculations based on Agreements A and B, effective August 1, 2010.

TABLE 9—BENEFITS

Monthly component	Pilots on undesignated waters	Pilots on designated waters
AGREEMENT A:		
Employer contribution, 401(K) plan (Monthly Wages × 5%)	$737.42	$1,106.13
Pension = $33.35 × 45.5 days	$1,517.43	$1,517.43
Health = $88.76 × 45.5 days	$4,038.58	$4,038.58
AGREEMENT B:		
Employer contribution, 401(K) plan (Monthly Wages × 5%)	$825.60	$1,238.40
Pension = $43.55 × 45.5 days	$1,981.53	$1,981.53
Health = $88.76 × 45.5 days	$4,038.58	$4,038.58
AGREEMENT A:		
Monthly total benefits	= $6,293.42	= $6,662.13
AGREEMENT A:		
Monthly total benefits × 9 months	= $56,641	= $59,959
AGREEMENT B:		
Monthly total benefits	= $6,845.71	= $7,258.51
AGREEMENT B:		
Monthly total benefits × 9 months	= $61,611	= $65,327

TABLE 10—TOTAL WAGES AND BENEFITS

	Pilots on undesignated waters	Pilots on designated waters
AGREEMENT A: Wages	$132,735	$199,103
AGREEMENT A: Benefits	+$56,641	+$59,959
AGREEMENT A: Total	= $189,376	= $259,062
AGREEMENT B: Wages	$148,608	$222,912
AGREEMENT B: Benefits	+$61,611	+$65,327
AGREEMENT B: Total	= $210,219	= $288,239

Table 11 shows that approximately one third of U.S. Great Lakes shipping deadweight tonnage operates under Agreement A, with the remaining two thirds operating under Agreement B.

TABLE 11—DEADWEIGHT TONNAGE BY AMOU AGREEMENT

Company	Agreement A	Agreement B
American Steamship Company		815,600
Mittal Steel USA, Inc		38,826
Key Lakes, Inc	361,385	
Total tonnage, each agreement	361,385	854,426
Percent tonnage, each agreement	361,385 ÷ 1,215,811 = 29.7238%	854,426 ÷ 1,215,811 = 70.2762%

Table 12 applies the percentage of tonnage represented by each agreement to the wages and benefits provided by each agreement, to determine the projected target rate of compensation on a tonnage-weighted basis.

TABLE 12—PROJECTED TARGET RATE OF COMPENSATION, WEIGHTED

	Undesignated waters	Designated waters
AGREEMENT A:		
Total wages and benefits × percent tonnage	$189,376 × 29.7238% = $56,290	$259,062 × 29.7238% = $77,003
AGREEMENT B:		
Total wages and benefits × percent tonnage	$210,219 × 70.2762% = $147,734	$288,239 × 70.2762% = $202,563
Total weighted average wages and benefits = projected target rate of compensation.	$56,290 + $147,734 = $204,024	$77,003 + $202,563 = $279,566

(b) Determine number of pilots needed. Subject to adjustment by the Coast Guard Director of Great Lakes Pilotage to ensure uninterrupted service, we determine the number of pilots needed for ratemaking purposes in each Area by dividing each Area's projected bridge hours, either by 1,000 (designated waters) or by 1,800 (undesignated waters).

Bridge hours are the number of hours a pilot is aboard a vessel providing pilotage service. Projected bridge hours are based on the vessel traffic that pilots are expected to serve. Based on historical data and information provided by pilots and industry, we project that vessel traffic in the 2010 navigation season, in all Areas, will remain unchanged from the 2009 projections noted in Table 13 of the 2009 final rule.

Table 13, below, shows the projected bridge hours needed for each Area, and the total number of pilots needed for ratemaking purposes after dividing those figures either by 1,000 or 1,800. As in 2008 and 2009, and for the same reasons, we rounded up to the next whole pilot except in Area 2 where we rounded up from 3.14 to 5, and in Area 4 where we rounded down from 4.07 to 4.

TABLE 13—NUMBER OF PILOTS NEEDED

Pilotage area	Projected 2010 bridge hours	Divided by 1,000 (Designated waters) or 1,800 (undesignated waters)	Pilots needed (total = 40)
Area 1	5,203	1,000	6
Area 2	5,650	1,800	5
Area 4	7,320	1,800	4
Area 5	5,097	1,000	6
Area 6	13,406	1,800	8
Area 7	3,259	1,000	4
Area 8	11,630	1,800	7

(c) Determine the projected target pilot compensation for each Area. The projection of new total target pilot compensation is determined separately for each pilotage Area by multiplying the number of pilots needed in each Area (*see* Table 13) by the projected target rate of compensation (*see* Table 12) for pilots working in that Area. Table 14 shows this calculation.

TABLE 14—PROJECTED TARGET PILOT COMPENSATION

Pilotage area	Pilots needed (total = 40)	Multiplied by target rate of compensation	Projected target pilot compensation
Area 1	6	× $279,566	$1,677,397
Area 2	5	× 204,024	1,020,120

TABLE 14—PROJECTED TARGET PILOT COMPENSATION—Continued

Pilotage area	Pilots needed (total = 40)	Multiplied by target rate of compensation	Projected target pilot compensation
Total, District One	11	n/a	2,697,517
Area 4	4	× 204,024	816,096
Area 5	6	× 279,566	1,677,397
Total, District Two	10	n/a	2,493,493
Area 6	8	× 204,024	1,632,191
Area 7	4	× 279,566	1,118,265
Area 8	7	× 204,024	1,428,167
Total, District Three	19	n/a	4,178,623

Step 4: Increase the projected pilot compensation in Step 3 by the expense multiplier in Step 2. This step yields a projected increase in operating costs necessary to support the increased projected pilot compensation. Table 15 shows this calculation.

TABLE 15—PROJECTED OPERATING EXPENSE

Pilotage area	Projected target pilot compensation	Multiplied by expense multiplier	Projected operating expense
Area 1	$1,677,397	× 0.33927	= $569,084
Area 2	1,020,120	× 0.57449	= 586,050
Total, District One	2,697,517	n/a	= 1,155,134
Area 4	816,096	× 0.67135	= 547,886
Area 5	1,677,397	× 0.50729	= 850,924
Total, District Two	2,493,493	n/a	= 1,398,810
Area 6	1,632,191	× 0.53926	= 880,177
Area 7	1,118,265	× 0.38049	= 425,493
Area 8	1,428,167	× 0.48087	= 686,767
Total, District Three	4,178,623	n/a	= 1,992,438

Step 5: Adjust the result in Step 4, as required, for inflation or deflation, and calculate projected total economic cost. Based on data from the U.S. Department of Labor's Bureau of Labor Statistics, we have multiplied the results in Step 4 by a 1.037 inflation factor, reflecting an average inflation rate of 3.7% in ''Midwest Economy—Consumer Prices'' between 2007 and 2008, the latest years for which data are available. Table 16 shows this calculation and the projected total economic cost.

TABLE 16—PROJECTED TOTAL ECONOMIC COST

Pilotage area	A. Projected operating expense	B. Increase, multiplied by inflation factor (= A × 1.037)	C. Projected target pilot compensation	D. Projected total economic cost (= B + C)
Area 1	$569,084	$590,140	$1,677,397	$2,267,537
Area 2	586,050	607,733	1,020,120	1,627,853
Total, District One	1,155,134	1,197,874	2,697,517	3,895,390
Area 4	547,886	568,158	816,096	1,384,253
Area 5	850,924	882,408	1,677,397	2,559,805
Total, District Two	1,398,810	1,450,566	2,493,493	3,944,058
Area 6	880,177	912,744	1,632,191	2,544,935
Area 7	425,493	441,236	1,118,265	1,559,501
Area 8	686,767	712,178	1,428,167	2,140,345
Total, District Three	1,992,438	2,066,158	4,178,623	6,244,781

Step 6: Divide the result in Step 5 by projected bridge hours to determine total unit costs. Table 17 shows this calculation.

TABLE 17—TOTAL UNIT COSTS

Pilotage area	A. Projected total economic cost	B. Projected 2009 bridge hours	Prospective (total) unit costs (A divided by B)
Area 1	$2,267,537	5,203	$435.81
Area 2	1,627,853	5,650	288.12
Total, District One	3,895,390	10,853	358.92
Area 4	1,384,253	7,320	189.11
Area 5	2,559,805	5,097	502.22
Total, District Two	3,944,058	12,417	317.63
Area 6	2,544,935	13,406	189.84
Area 7	1,559,501	3,259	478.52
Area 8	2,140,345	11,630	184.04
Total, District Three	6,244,781	28,295	220.70
Overall	14,084,230	51,565	273.14

Step 7: Divide prospective unit costs (total unit costs) in Step 6 by the base period unit costs in Step 1. Table 18 shows this calculation, which expresses the percentage change between the total unit costs and the base unit costs. The results, for each Area, are identical with the percentage increases listed in Table 1.

TABLE 18—PERCENTAGE CHANGE IN UNIT COSTS

Pilotage area	A. Prospective unit costs	B. Base period unit costs	C. Percentage change from base (A divided by B; result expressed as percentage)
Area 1	$435.81	$416.47	4.65
Area 2	288.12	273.54	5.33
Total, District One	358.92	342.06	4.93
Area 4	189.11	179.30	5.47
Area 5	502.22	478.46	4.96
Total, District Two	317.63	302.10	5.14
Area 6	189.84	180.33	5.27
Area 7	478.52	456.90	4.73
Area 8	184.04	174.98	5.17
Total, District Three	220.70	209.99	5.10
Overall	273.14	259.97	5.07

Step 8: Adjust the base period rates by the percentage change in unit costs in Step 7. Table 19 shows this calculation.

TABLE 19—BASE PERIOD RATES ADJUSTED BY PERCENTAGE CHANGE IN UNIT COSTS*

Pilotage	A. Base period rate	B. Percentage change in unit costs	C. Increase in base rate (A × B%)	D. Adjusted rate (A + C, rounded to nearest dollar)
Area		(Multiplying Factor)		
Area 1:		4.65 (1.0465)		
—Basic pilotage	$16.95/km, $29.99/mi		$0.78/km, $1.39/mi	$17.73/km, $31.38/mi.
—Each lock transited	375.47		17.44	393.
—Harbor movage	1,229.41		57.11	1,287.
—Minimum basic rate, St. Lawrence River.	820.04		38.09	858.

TABLE 19—BASE PERIOD RATES ADJUSTED BY PERCENTAGE CHANGE IN UNIT COSTS*—Continued

Pilotage	A. Base period rate	B. Percentage change in unit costs	C. Increase in base rate (A × B%)	D. Adjusted rate (A + C, rounded to nearest dollar)
Area		(Multiplying Factor)		
—Maximum rate, through trip	3,599.58		167.20	3,767.
Area 2:		5.33 (1.0533)		
—6-hr. period	817.63		43.56	861.
—Docking or undocking	779.92		41.55	821.
Area 4:		5.47 (1.0547)		
—6-hr. period	722.05		39.49	762.
—Docking or undocking	556.46		30.44	587.
—Any point on Niagara River below Black Rock Lock.	1,420.45		77.69	1,498.
Area 5 between any point on or in:		4.96 (1.0496)		
—Toledo or any point on Lake Erie W. of Southeast Shoal.	1,299.46		64.51	1,364.
—Toledo or any point on Lake Erie W. of Southeast Shoal & Southeast Shoal.	2,198.99		109.16	2,308.
—Toledo or any point on Lake Erie W. of Southeast Shoal & Detroit River.	2,855.20		141.74	2,997.
—Toledo or any point on Lake Erie W. of Southeast Shoal & Detroit Pilot Boat.	2,198.99		109.16	2,308.
—Port Huron Change Point & Southeast Shoal (when pilots are not changed at the Detroit Pilot Boat).	3,829.80		190.12	4,020.
—Port Huron Change Point & Toledo or any point on Lake Erie W. of Southeast Shoal (when pilots are not changed at the Detroit Pilot Boat).	4,436.82		220.26	4,657.
—Port Huron Change Point & Detroit River.	2,877.20		142.83	3,020.
—Port Huron Change Point & Detroit Pilot Boat.	2,237.82		111.09	2,349.
—Port Huron Change Point & St. Clair River.	1,590.68		78.97	1,670.
—St. Clair River	1,299.46		64.51	1,364.
—St. Clair River & Southeast Shoal (when pilots are not changed at the Detroit Pilot Boat).	3,829.80		190.12	4,020.
—St. Clair River & Detroit River/Detroit Pilot Boat.	2,877.20		142.83	3,020.
—Detroit, Windsor, or Detroit River.	1,299.46		64.51	1,364.
—Detroit, Windsor, or Detroit River & Southeast Shoal.	2,198.99		109.16	2,308.
—Detroit, Windsor, or Detroit River & Toledo or any point on Lake Erie W. of Southeast Shoal.	2,855.20		141.74	2,997.
—Detroit, Windsor, or Detroit River & St. Clair River.	2,877.20		142.83	3,020.
—Detroit Pilot Boat & Southeast Shoal.	1,590.68		78.97	1,670.
—Detroit Pilot Boat & Toledo or any point on Lake Erie W. of Southeast Shoal.	2,198.99		109.16	2,308.
—Detroit Pilot Boat & St. Clair River.	2,877.20		142.83	3,020.
Area 6:		5.27 (1.0527)		
—6-hr. period	622.93		32.84	656.
—Docking or undocking	591.72		31.20	623.
Area 7 between any point on or in:		4.73 (1.0473)		
—Gros Cap & De Tour	2,442.98		115.57	2,559.
—Algoma Steel Corp. Wharf, Sault Ste. Marie, Ont. & De Tour.	2,442.98		115.57	2,559.

TABLE 19—BASE PERIOD RATES ADJUSTED BY PERCENTAGE CHANGE IN UNIT COSTS*—Continued

Pilotage	A. Base period rate	B. Percentage change in unit costs	C. Increase in base rate (A × B%)	D. Adjusted rate (A + C, rounded to nearest dollar)
Area		(Multiplying Factor)		
—Algoma Steel Corp. Wharf, Sault Ste. Marie, Ont. & Gros Cap.	920.03		43.52	964.
—Any point in Sault Ste. Marie, Ont., except the Algoma Steel Corp. Wharf & De Tour.	2,047.67		96.87	2,145.
—Any point in Sault Ste. Marie, Ont., except the Algoma Steel Corp. Wharf & Gros Cap.	920.03		43.52	964.
—Sault Ste. Marie, MI & De Tour.	2,047.67		96.87	2,145.
—Sault Ste. Marie, MI & Gros Cap.	920.03		43.52	964.
—Harbor movage	920.03		43.52	964
Area 8:		5.17 (1.0517)		
—6 hr. period	549.44		28.42	578.
—Docking or undocking	522.20		27.02	549.

* Rates for "Cancellation, delay or interruption in rendering services (§ 401.420)" and "Basic Rates and charges for carrying a U.S. pilot beyond the normal change point, or for boarding at other than the normal boarding point (§ 401.428)" are not reflected in this table but have been increased by 5.07% across all areas.

V. Regulatory Analyses

We developed this proposed rule after considering numerous statutes and executive orders related to rulemaking. Below, we summarize our analyses based on 13 of these statutes or executive orders.

A. Regulatory Planning and Review

Executive Order 12866, "Regulatory Planning and Review," 58 FR 51735, October 4, 1993, requires a determination whether a regulatory action is "significant" and therefore subject to review by the Office of Management and Budget (OMB) and subject to the requirements of the Executive Order. This rulemaking is not significant under Executive Order 12866 and will not be reviewed by OMB.

The Coast Guard is required to conduct an annual review of pilotage rates on the Great Lakes and, if necessary, adjust these rates to align compensation levels between Great Lakes pilots and industry. See the "Background and Purpose" section for a detailed explanation of the legal authority and requirements for the Coast Guard to conduct an annual review and provide possible adjustments of pilotage rates on the Great Lakes. Based on our annual review for this rulemaking, we are proposing an adjustment to the pilotage rates for the 2010 shipping season to generate sufficient revenue to cover allowable expenses, target pilot compensation, and returns on investment.

This proposed rule would implement a 5.07 percent overall rate adjustment for the Great Lakes system over the current rate as adjusted in the 2009 final rule. These adjustments to Great Lakes pilotage rates meet the requirements set forth in 46 CFR part 404 for similar compensation levels between Great Lakes pilots and industry. They also include adjustments for inflation and changes in association expenses to maintain these compensation levels.

In general, we expect an increase in pilotage rates for a certain area to result in additional costs for shippers using pilotage services in that area, while a decrease would result in a cost reduction or savings for shippers in that area. This proposed rule would result in a distributional effect that transfers payments (income) from affected shippers (vessel owners and operators) to the Great Lakes' pilot associations through Coast Guard regulated pilotage rates.

The shippers affected by these rate adjustments are those owners and operators of domestic vessels operating on register (employed in the foreign trade) and owners and operators of foreign vessels on a route within the Great Lakes system. These owners and operators must have pilots or pilotage service as required by 46 U.S.C. 9302. There is no minimum tonnage limit or exemption for these vessels. However, the Coast Guard issued a policy position several years ago stating that the statute applies only to commercial vessels and not to recreational vessels.

Owners and operators of other vessels that are not affected by this proposed rule, such as recreational boats and vessels only operating within the Great Lakes system, may elect to purchase pilotage services. However, this election is voluntary and does not affect the Coast Guard's calculation of the rate increase and is not a part of our estimated national cost to shippers.

We reviewed a sample of pilot source forms, which are the forms used to record pilotage transactions on vessels, and discovered very few cases of U.S. Great Lakes vessels (*i.e.,* domestic vessels without registry operating only in the Great Lakes) that purchased pilotage services. We found a case where the vessel operator purchased pilotage service in District One to presumably leave the Great Lakes system. We assume some vessel owners and operators may also choose to purchase pilotage services if their vessels are carrying hazardous substances or were navigating the Great Lakes system with inexperienced personnel. Based on information from the Coast Guard Office of Great Lakes Pilotage, we have determined that these vessels voluntarily chose to use pilots and, therefore, are exempt from pilotage requirements.

We used 2006–2008 vessel arrival data from the Coast Guard's Marine Information for Safety and Law Enforcement (MISLE) system to estimate the average annual number of vessels affected by the rate adjustment to be 208 vessels that journey into the Great Lakes system. These vessels entered the Great Lakes by transiting through or in part of at least one of the three pilotage Districts before leaving the Great Lakes system. These vessels often make more than one distinct stop, docking, loading, and unloading at facilities in Great Lakes ports. Of the total trips for the 208 vessels, there were approximately 923 annual U.S. port arrivals before the vessels left the Great Lakes system, based on 2006–2008 vessel data from MISLE.

The impact of the rate adjustment to shippers is estimated from the district pilotage revenues. These revenues represent the direct and indirect costs (''economic costs'') that shippers must pay for pilotage services. The Coast Guard sets rates so that revenues equal the estimated cost of pilotage.

We estimate the additional impact (costs or savings) of the rate adjustment in this proposed rule to be the difference between the total projected revenue needed to cover costs based on the 2009 rate adjustment and the total projected revenue needed to cover costs in this proposed rule for 2010. Table 20 details additional costs or savings by area and district.

TABLE 20—RATE ADJUSTMENT AND ADDITIONAL IMPACT OF PROPOSED RULE ($U.S.; NON-DISCOUNTED)[1]

	Total projected expenses in 2009	Proposed rate change	Total projected expenses in 2010[2]	Additional revenue or cost of this rulemaking[3]
Area 1	$2,166,873	1.0465	$2,267,537	$100,664
Area 2	1,545,503	1.0533	1,627,853	82,350
Total, District One	3,712,376		3,895,390	183,014
Area 4	1,312,463	1.0547	1,384,253	71,791
Area 5	2,438,725	1.0496	2,559,805	121,080
Total, District Two	3,751,188		3,944,058	192,870
Area 6	2,417,474	1.0527	2,544,935	127,461
Area 7	1,489,052	1.0473	1,559,501	70,449
Area 8	2,035,052	1.0517	2,140,345	105,293
Total, District Three	5,941,578		6,244,781	303,203
All Districts	13,405,142		14,084,230	679,088

[1] Some values may not total due to rounding.
[2] Rate changes are calculated for areas only. District totals reflect arithmetic totals and are for informational and discussion purposes. See discussion in proposed rule for further details.
[3] Additional Revenue or Cost of this Rulemaking = 'Total Projected Expenses in 2010' – 'Total Projected Expenses in 2009'.

After applying the rate change in this proposed rule, the resulting difference between the projected revenue in 2009 and the projected revenue in 2010 is the annual impact to shippers from this proposed rule. This figure will be equivalent to the total additional payments or savings that shippers will incur for pilotage services from this rule. As discussed earlier, we consider a reduction in payments to be a cost savings.

The impact of the rate adjustment in this proposed rule to shippers varies by area and district. The annual non-discounted costs of the rate adjustments in Districts 1 and 2 would be approximately $183,000 and $193,000, respectively, while District 3 would experience an annual non-discounted cost of approximately $300,000. To calculate an exact cost or savings per vessel is difficult because of the variation in vessel types, routes, port arrivals, commodity carriage, time of season, conditions during navigation, and preferences for the extent of pilotage services on designated and undesignated portions of the Great Lakes system. Some owners and operators would pay more and some would pay less depending on the distance and port arrivals of their vessels' trips. However, the annual cost or savings reported above does capture all of the additional cost the shippers face as a result of the rate adjustment in this rule.

As Table 20 indicates, all areas would experience an increased annual cost due to this proposed rulemaking. The overall impact of the proposed rule would be an additional cost to shippers of just over $679,000 across all three districts, due primarily to an increase in benchmark contractual wages and benefits and an inflation adjustment.

B. Small Entities

Under the Regulatory Flexibility Act (5 U.S.C. 601–612), we have considered whether this proposed rule would have a significant economic impact on a substantial number of small entities. The term ''small entities'' comprises small businesses, not-for-profit organizations that are independently owned and operated and are not dominant in their fields, and governmental jurisdictions with populations of less than 50,000 people.

We expect entities affected by the proposed rule would be classified under the North American Industry Classification System (NAICS) code subsector 483–Water Transportation, which includes one or all of the following 6-digit NAICS codes for freight transportation: 483111–Deep Sea Freight Transportation, 483113–Coastal and Great Lakes Freight Transportation, and 483211–Inland Water Freight Transportation. According to the Small Business Administration's definition, a U.S. company with these NAICS codes and employing less than 500 employees is considered a small entity.

For the proposed rule, we reviewed recent company size and ownership data from 2006–2008 Coast Guard MISLE data and business revenue and size data provided by Reference USA and Dunn and Bradstreet. We were able to gather revenue and size data or link the entities to large shipping conglomerates for 22 of the 24 affected entities in the United States. We found that large, mostly foreign-owned, shipping conglomerates or their subsidiaries owned or operated all vessels engaged in foreign trade on the Great Lakes. We assume that new industry entrants will be comparable in ownership and size to these shippers.

There are three U.S. entities affected by the proposed rule that receive revenue from pilotage services. These are the three pilot associations that provide and manage pilotage services within the Great Lakes districts. Two of the associations operate as partnerships and one operates as a corporation. These associations are classified with the same NAICS industry classification and small entity size standards described above, but they have far fewer than 500 employees: Approximately 65 total employees combined. We expect no adverse impact to these entities from this proposed rule since all associations receive enough revenue to balance the projected expenses associated with the projected number of bridge hours and pilots.

Therefore, the Coast Guard has determined that this proposed rule would not have a significant economic impact on a substantial number of small entities under 5 U.S.C. 605(b). If you think that your business, organization, or governmental jurisdiction qualifies as a small entity and that this proposed rule would have a significant economic impact on it, please submit a comment to the Docket Management Facility at the address under **ADDRESSES**. In your comment, explain why you think it qualifies and how and to what degree this proposed rule would economically affect it.

C. Assistance for Small Entities

Under section 213(a) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121), we offer to assist small entities in understanding the proposed rule so that they could better evaluate its effects on them and participate in the rulemaking. If the proposed rule would affect your small business, organization, or governmental jurisdiction and you have questions concerning its provisions or options for compliance, please call Mr. Paul M. Wasserman, Chief,Great Lakes Pilotage Branch, Commandant (CG–54122), U.S. Coast Guard, at 202–372–1525, by fax 202–372–1929, or by e-mail at *Paul.M.Wasserman@uscg.mil.* Small businesses may send comments on the actions of Federal employees who enforce, or otherwise determine compliance with, Federal regulations to the Small Business and Agriculture Regulatory Enforcement Ombudsman and the Regional Small Business Regulatory Fairness Boards. The Ombudsman evaluates these actions annually and rates each agency's responsiveness to small business. If you wish to comment on actions by employees of the Coast Guard, call 1–888–REG–FAIR (1–888–734–3247).

D. Collection of Information

This proposed rule would call for no new collection of information under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520). This rule does not change the burden in the collection currently approved by the Office of Management and Budget (OMB) under OMB Control Number 1625–0086, Great Lakes Pilotage Methodology.

E. Federalism

A rule has implications for federalism under Executive Order 13132, Federalism, if it has a substantial direct effect on State or local governments and would either preempt State law or impose a substantial direct cost of compliance on them. We have analyzed this rule under that Order and have determined that it does not have implications for federalism because there are no similar State regulations, and the States do not have the authority to regulate and adjust rates for pilotage services in the Great Lakes system.

F. Unfunded Mandates Reform Act

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

G. Taking of Private Property

This rule would not affect a taking of private property or otherwise have taking implications under Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

H. Civil Justice Reform

This rule meets applicable standards in sections 3(a) and 3(b)(2) of Executive Order 12988, Civil Justice Reform, to minimize litigation, eliminate ambiguity, and reduce burden.

I. Protection of Children

We have analyzed this rule under Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks. This rule is not an economically significant rule and does not create an environmental risk to health or risk to safety that may disproportionately affect children.

J. Indian Tribal Governments

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

K. Energy Effects

We have analyzed this rule under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use. We have determined that it is not a ''significant energy action'' under that order because it is not a ''significant regulatory action'' under Executive Order 12866 and is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The Administrator of the Office of Information and Regulatory Affairs has not designated it as a significant energy action. Therefore, it does not require a Statement of Energy Effects under Executive Order 13211.

L. Technical Standards

The National Technology Transfer and Advancement Act (NTTAA) (15 U.S.C. 272 note) directs agencies to use voluntary consensus standards in their regulatory activities unless the agency provides Congress, through the Office of Management and Budget, with an explanation of why using these standards would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.,* specifications of materials, performance, design, or operation; test methods; sampling procedures; and related management systems practices) that are developed or adopted by voluntary consensus standards bodies. This rule does not use technical standards. Therefore, we did not consider the use of voluntary consensus standards.

M. Environment

We have analyzed this rule under Department of Homeland Security Management Directive 023–01 and Commandant Instruction M16475.lD, which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA)(42 U.S.C. 4321–4370f), and have concluded that this action is one of a category of actions which do not individually or cumulatively have a significant effect on the human environment. This rule is categorically excluded under section 2.B.2, figure 2–1, paragraph (34)(a) of the Instruction. Paragraph 34(a) pertains to minor regulatory changes that are editorial or procedural in nature. This rule adjusts rates in accordance with applicable statutory and regulatory mandates. An environmental analysis checklist and a categorical exclusion determination are available in the docket where indicated under ADDRESSES.

List of Subjects in 46 CFR Part 401

Administrative practice and procedure, Great Lakes, Navigation (water), Penalties, Reporting and recordkeeping requirements, Seamen.

For the reasons discussed in the preamble, the Coast Guard proposes to amend 46 CFR Part 401 as follows:

PART 401—GREAT LAKES PILOTAGE REGULATIONS

1. The authority citation for part 401 continues to read as follows:

Authority: 46 U.S.C. 2104(a), 6101, 7701, 8105, 9303, 9304; Department of Homeland Security Delegation No. 0170.1; 46 CFR 401.105 also issued under the authority of 44 U.S.C. 3507.

2. In § 401.405, revise paragraphs (a) and (b) to read as follows:

§ 401.405 Basic rates and charges on the St. Lawrence River and Lake Ontario.

* * * * *

(a) Area 1 (Designated Waters):

Service	St. Lawrence River
Basic Pilotage	$17.73 per Kilometer or $31.38 per mile.[1]
Each Lock Transited	$393.[1]
Harbor Movage	$1287.[1]

[1] The minimum basic rate for assignment of a pilot in the St. Lawrence River is $858, and the maximum basic rate for a through trip is $3,767.

(b) Area 2 (Undesignated Waters):

Service	Lake Ontario
Six-Hour Period	$861
Docking or Undocking	821

3. In § 401.407, revise paragraphs (a) and (b) to read as follows:

§ 401.407 Basic rates and charges on Lake Erie and the navigable waters from Southeast Shoal to Port Huron, MI.

* * * * *

(a) Area 4 (Undesignated Waters):

Service	Lake Erie (East of Southeast Shoal)	Buffalo
Six-Hour Period	$762	$762
Docking or Undocking	587	587
Any Point on the Niagara River below the Black Rock Lock.	N/A	1,498

(b) Area 5 (Designated Waters):

Any point on or in	Southeast Shoal	Toledo or any point on Lake Erie west of Southeast Shoal	Detroit River	Detroit Pilot Boat	St. Clair River
Toledo or any point on Lake Erie west of Southeast Shoal	$2,308	$1,364	$2,997	$2,308	N/A
Port Huron Change Point	[1] 4,020	[1] 4,657	3,020	2,349	1,670
St. Clair River	[1] 4,020	N/A	3,020	3,020	1,364
Detroit or Windsor or the Detroit River	2,308	2,997	1,364	N/A	3,020
Detroit Pilot Boat	1,670	2,308	N/A	N/A	3,020

[1] When pilots are not changed at the Detroit Pilot Boat.

4. In § 401.410, revise paragraphs (a), (b), and (c) to read as follows:

§ 401.410 Basic rates and charges on Lakes Huron, Michigan, and Superior, and the St. Mary's River.

* * * * *

(a) Area 6 (Undesignated Waters):

Service	Lakes Huron and Michigan
Six-Hour Period	$656
Docking or Undocking	623

(b) Area 7 (Designated Waters):

Area	De Tour	Gros Cap	Any Harbor
Gros Cap	$2,559	N/A	N/A
Algoma Steel Corporation Wharf at Sault Ste. Marie Ontario	2,559	964	N/A
Any point in Sault Ste. Marie, Ontario, except the Algoma Steel Corporation Wharf	2,145	964	N/A
Sault Ste. Marie, MI	2,145	964	N/A
Harbor Movage	N/A	N/A	$964

(c) Area 8 (Undesignated Waters):

Service	Lake Superior
Six-Hour Period	$578
Docking or Undocking	549

§ 401.420 [Amended]

5. In § 401.420—

a. In paragraph (a), remove the number ''$113'' and add, in its place, the number ''$119''; and remove the number ''$1,777'' and add, in its place, the number ''$1,867''.

b. In paragraph (b), remove the number ''$113'' and add, in its place, the number ''$119''; and remove the number ''$1,777'' and add, in its place, the number ''$1,867''.

c. In paragraph (c)(1), remove the number ''$671'' and add, in its place, the number ''$705''.

d. In paragraph (c)(3), remove the number ''$113'' and add, in its place, the number ''$119''; and, also in paragraph (c)(3), remove the number ''$1,777'' and add, in its place, the number ''$1,867''.

§ 401.428 [Amended]

6. In § 401.428, remove the number ''$684'' and add, in its place, the number ''$719''.

Dated: October 26, 2009.

Kevin S. Cook,

Rear Admiral, U.S. Coast Guard, Director of Prevention Policy.

[FR Doc. E9–26212 Filed 10–29–09; 8:45 am]

BILLING CODE 4910–15–P

DEPARTMENT OF TRANSPORTATION

National Highway Traffic Safety Administration

49 CFR Part 571

[Docket No. NHTSA–09–0117]

RIN 2127–AK42

Federal Motor Vehicle Safety Standards; New Pneumatic and Certain Specialty Tires

AGENCY: National Highway Traffic Safety Administration (NHTSA), Department of Transportation (DOT).

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: This NPRM proposes to amend Federal Motor Vehicle Safety Standard (FMVSS) No. 109, *New pneumatic and certain specialty tires,* to change the test pressure for the physical dimensions test for T-type tires (temporary use spare tires) from 52 pounds per square inch (psi) to 60 psi. A 60-psi test pressure for the physical dimensions test would marginally increase the stringency of the test while harmonizing FMVSS No. 109 with international and voluntary consensus standards. This NPRM responds to a petition for rulemaking from the Tire & Rim Association.

DATES: You should submit your comments early enough to ensure that the Docket receives them no later than December 29, 2009.

ADDRESSES: You may submit comments (identified by the DOT Docket ID Number above) 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.
- *Fax:* 202–493–2251

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, *see* the Public Participation heading of the Supplementary Information section of this document. 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 at *http://www.dot.gov/privacy.html.*

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: Santiago Navarro or George Soodoo, NHTSA Office of Rulemaking, telephone 202–366–2720, fax 202–493–2739. For legal issues, you may call Deirdre Fujita, NHTSA Office of Chief Counsel, telephone 202–366–2992, fax 202–366–3820. You may send mail to these officials at the National Highway Traffic Safety Administration, 1200 New Jersey Avenue, SE., West Building, Washington, DC, 20590.

SUPPLEMENTARY INFORMATION:

I. Background

a. T-Type Spare Tires

NHTSA regulates ''T-type'' spare tires under FMVSS No. 109, *New pneumatic and certain specialty tires.* A ''T-type'' spare tire refers to a type of spare tire that is manufactured to be used as a temporary substitute by the consumer for a conventional tire that failed. For T-type spare tires, FMVSS No. 109 specifies tire dimensions and laboratory test requirements for bead unseating resistance, strength, endurance, and high speed performance. The standard also defines tire load ratings and specifies labeling requirements for the tires.

NHTSA amended FMVSS No. 109 to permit the manufacture of T-type (then known as ''60-psi'') spare tires in 1977, describing them as ''differ[ing] substantially in specification and construction from conventional tires * * * [with] a higher inflation pressure (60 psi), different dimensions, and a shorter treadwear life than conventional tires.'' [1] The agency adopted endurance and high-speed performance tests, strength requirements, a resistance to bead unseating test, and a physical dimensions test, which were appropriate for the temporary use tires. Today's NPRM proposes an amendment to the physical dimensions test.

b. Physical Dimensions Test

The purpose of the physical dimensions test is to measure the tire's growth under inflated conditions and to determine if it is within allowable growth limits. If a tire exceeds allowable growth limits in the physical dimensions test, that indicates that there could be a safety risk from that tire not matching well with its rim, or not fitting well with the vehicle to which it is attached. Either of these mis-matches could present safety risks.

All T-type tires must comply with growth limits as specified by S4.2.2.2 of FMVSS No. 109, which states that the tire's actual section width and overall width may not exceed the specified section width [2] by more than 7 percent or 10 millimeters (0.4 inches),

[1] 42 FR 12869, 12870 (March 7, 1977).

[2] S4.2.2.2 states that the measured section width ''shall not exceed the section width *specified in a submission made by an individual manufacturer, pursuant to S4.4.1(a) or in one of the publications described in S4.4.1(b) for its size designation and type* * * *.'' (Emphasis added.) The ''publications described in S4.4.1(b)'' refer to the year books published by various tire manufacturer associations, such as T&RA. As a practical matter, individual tire manufacturers generally submit section width information to associations like T&RA for inclusion in the year books, rather than submitting such information directly to NHTSA, although FMVSS No. 109 allows the latter option.

whichever is greater. The ''section width'' of a tire is defined in S3 of FMVSS No. 109 as ''the linear distance between the exteriors of the sidewalls of an inflated tire, excluding elevations due to labeling, decoration, or protective bands.''

The test procedure for the physical dimensions test is specified in S5.1 of FMVSS No. 109. That section states that the tire is mounted on the appropriate test rim and inflated to the pressure listed in Table II of the standard, which for 60-psi tires is 52 psi. The tire is then conditioned at ambient temperature for 24 hours, at which point the inflation is checked and adjusted back to 52 psi if necessary, and then the tire is measured again. The later measurement is then compared with the initial measurement to determine the tire's growth.

c. Test Pressure

NHTSA requires tire manufacturers to specify both a ''recommended'' pressure and a ''maximum permissible inflation pressure.'' The recommended inflation pressure is the operational inflation pressure needed to support the weight of the vehicle when loaded to its gross vehicle weight rating. The maximum permissible inflation pressure, which is required to be molded on the tire's sidewall, is the maximum pressure beyond which the tire should not be inflated. Usually a manufacturer's recommended inflation pressure is lower than the tire's maximum pressure labeled on the tire sidewall.

Since most tires have a recommended inflation pressure that is lower than the specified maximum pressure for the tire, the test pressure that NHTSA uses to test tires dynamically on a test wheel is generally lower than the maximum pressure labeled on the sidewall. Further, most tires are operated at some level of under-inflation during normal service. To reflect this real-world use, FMVSS No. 109's dynamic test procedures generally specify under-inflating a tire when testing the tire on the road-wheel. Moreover, dynamic tests are more stringent when the tire is tested at an inflation pressure lower than the pressure required to support the given test load. Under-inflating a tire eventually results in greater heat build-up due to over-deflection of a tire's sidewall, which increases the likelihood of tire failure.

Consistent with this approach, in the 1977 final rule NHTSA determined that T-type (60 psi) tires should be tested to all of the FMVSS No. 109 tests at a test pressure lower than the tire's maximum permissible inflation pressure of 60 psi. For the physical dimensions test, the agency determined that a 52-psi value reflects an operational inflation pressure appropriate for use in the test. The 52-psi maximum permissible inflation pressure adopted in 1977 has not been changed since that final rule.

II. Tire & Rim Association Petition

In a July 13, 2007 petition, the Tire & Rim Association (T&RA) requested that the agency make a technical correction [3] to Table II of FMVSS No. 109 regarding T-type tires. Specifically, T&RA requested that ''the inflation pressure for the measurement of physical dimensions in Table II be changed from 52 psi to 60 psi.'' T&RA stated that ''There is only one application inflation pressure for T-type tires, 60 psi,'' and that therefore ''this is the appropriate pressure for the subject measurement.'' The petitioner also stated that the inflation pressure for the bead unseating, tire strength, and tire endurance test should remain at 52 psi.

III. Agency Proposal

We concur with the petitioner that rulemaking is warranted to change the inflation pressure for the physical dimensions test, specified in Table II of the standard, from 52 psi to 60 psi. We are not persuaded, however, by the petitioner's reasoning that the pressure should be changed because ''there is only one application inflation pressure for T-type tires, 60 psi, and consequently we believe that this is the appropriate pressure for the subject measurement.'' The agency rejected in 1977 the similar view that because these tires do not have a ''design'' load level but only a single load level at its maximum inflation pressure of 60 psi, the single load level (60 psi) constituted the design load level. The petitioner did not provide reasons as to why we should change the conclusion we came to in 1977 to conclude now that a pressure of 60 psi would better reflect those tires' normal service inflation pressure.[4]

Instead, we are proposing to raise the inflation pressure specification for the physical dimensions for two other reasons. First, raising the inflation pressure makes engineering sense because doing so would increase the stringency of the test under conditions that are within the realm of real world use. The physical dimensions test is a static test where the stringency of the test is not greater at lower inflation pressure but at higher inflation pressures. This is because the tire expands at higher inflation pressures, which means that it would be closer to the growth limit of its section width at a higher inflation pressure. If the physical dimensions test pressure for T-type tires were increased to 60 psi, then the test would become incrementally more stringent than at 52 psi, because the additional growth due to the higher inflation pressure would have to be within the current limit established in FMVSS No. 109. The physical dimensions test contrasts, in this respect, with the dynamic tests performed on the road-wheel. It is also conceivable that the tires would be operated at a 60 psi (or lower) inflation pressure since that is the inflation pressure assigned the tire by the manufacturer.

Second, raising the test pressure for the physical dimensions test for T-type tires from 52 psi to 60 psi is consistent with international harmonization. The European regulation which covers T-type tires, ECE Regulation 30, specifies that those tires be tested for physical dimensions at ''4.2 bar,'' which is 420 kPa or the metric equivalent of 60 psi.[5] The Japanese regulation, Automobile Type Approval Handbook for Japanese Certification,[6] also specifies that the inflation pressure of the T-type spare tires be 420 kPa when measuring the tire physical dimensions. Tire manufacturers, and ultimately, consumers, can expect to achieve cost savings through the harmonization of differing sets of standards. T-type tires are prepared for the world market. It would be more economically efficient for manufacturers to use the same test procedures and meet the same performance requirements worldwide. This proposal helps to achieve these benefits.

We believe that existing 60-psi T-type spare tires will be able to pass the amended physical dimensions test. Tires are designed to hold a very stable shape within their possible range of pressure, but especially at their operating pressure, which for T-type tires is 60 psi. Further, as mentioned above, existing European and Japanese regulations already specify that T-type tires be tested for physical dimensions

[3] The agency believes that the petition should be addressed by this notice and comment rulemaking rather than by way of a technical correction.

[4] Indeed, for the dynamic tests which T-type tires must pass under FMVSS No. 109, such as the endurance and high-speed tests, we would not concur that raising the 52 psi inflation pressure to 60 psi would be justified on the basis that ''there is only one application inflation pressure [of 60 psi].''

[5] ECE Regulation No. 30, Annex 6, para. 1.2.5. *Available at http://www.unece.org/trans/main/wp29/wp29regs/r030r3e.doc.*

[6] Automobile Type Approval Handbook for Japanese Certification, Safety Regulations for Road Vehicles, Technical Standards For Pneumatic Tyres For Passenger-Use Motor Vehicles, Annex 3, 1–2–5.

at the metric equivalent of 60 psi, and as we believe that tire manufacturers develop similarly designed T-type tires for the U.S., European, and Japanese markets, T-type tires would be able to comply with the 60-psi requirement. Additionally, we note that the request to raise the physical dimensions test pressure came from a tire manufacturer trade association, which indicates that meeting the amended test is practicable. Thus, we anticipate that the costs of this proposed change to FMVSS No. 109, if any, would be minimal.

IV. Other Issues

This NPRM proposes other changes to FMVSS No. 109. These changes are minor and are as follows:

- The petitioner T&RA suggested that Table II's references to CT tires should be deleted. NHTSA tentatively agrees to this change since CT tires are no longer manufactured for sale in the U.S. Text in FMVSS No. 109 relating to CT tires (in S3, S4.2.1(b), S4.3.4 (inflation pressures related to CT tires), and in Table I–C) would also be removed.
- S4.4.1(b) would be revised to update the list of tire industry organizations, to make the list consistent with that established in the upgrade of FMVSS No. 139, ''New pneumatic radial tires for light vehicles.'' [7]
- Appendix A would be redesignated ''Appendix'' and moved to the end of the standard, following the current Table II of the standard. The first three sentences of the appendix would be corrected to remove references to any ''tables,'' which are no longer set forth in the appendix, and to update the address of NHTSA.

V. Proposed Effective Date

NHTSA proposes that a final rule on this rulemaking, assuming one is issued, would be effective 180 days after publication of the rule in the **Federal Register**. Optional early compliance would be permitted.

VI. Rulemaking Analyses and Notices

Executive Order 12866 and DOT Regulatory Policies and Procedures

This rulemaking document was not reviewed by the Office of Management and Budget under E.O. 12866. It is not considered to be significant under E.O. 12866 or the Department's Regulatory Policies and Procedures (44 FR 11034; Feb. 26, 1979). This NPRM proposes to increase slightly the stringency of an existing test applicable to T-type spare tires for passenger vehicles. The rulemaking would not affect current costs of testing T-type tires to FMVSS No. 109's performance requirements. The minimal impacts of today's amendment do not warrant preparation of a regulatory evaluation.

Regulatory Flexibility Act

In compliance with the Regulatory Flexibility Act, 5 U.S.C. 601 *et seq.,* NHTSA has evaluated the effects of this action on small entities. I hereby certify that this proposed rule would not have a significant impact on a substantial number of small entities. The NPRM would affect tire manufacturers who manufacture T-type tires, none of which, according to the agency's knowledge, are small businesses. Even if there were a substantial number of small businesses manufacturing T-type tires, these entities would not be significantly affected by a final rule since to the agency's knowledge all currently manufactured T-type tires would meet the proposed amendment. The rulemaking would not affect current costs of testing T-type tires to FMVSS No. 109's performance requirements.

Executive Order 13132 (Preemption)

NHTSA has examined today's NPRM pursuant to E.O. 13132 (64 FR 43255; Aug. 10, 1999) and concluded that no additional consultation with States, local governments, or their representatives is mandated beyond the rulemaking process. The agency has concluded that the rulemaking would not have federalism implications because a final rule, if issued, 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.''

Further, no consultation is needed to discuss the issue of preemption in connection with today's proposed rule. The issue of preemption can arise in connection with NHTSA rules in at least two ways. First, the National Traffic and Motor Vehicle Safety Act contains an express preemption provision: ''When a motor vehicle safety standard is in effect under this chapter, a State or a political subdivision of a State may prescribe or continue in effect a standard applicable to the same aspect of performance of a motor vehicle or motor vehicle equipment only if the standard is identical to the standard prescribed under this chapter.'' 49 U.S.C. 30103(b)(1). It is this statutory command that unavoidably preempts State legislative and administrative law, not today's rulemaking, so consultation would be unnecessary.

Second, the Supreme Court has recognized the possibility of implied preemption: in some instances, State requirements imposed on motor vehicle manufacturers, including sanctions imposed by State tort law, can stand as an obstacle to the accomplishment and execution of a NHTSA safety standard. When such a conflict is discerned, the Supremacy Clause of the Constitution makes the State requirements unenforceable. See *Geier* v. *American Honda Motor Co.,* 529 U.S. 861 (2000). However, NHTSA has considered the nature and purpose of today's proposed rule and does not currently foresee any potential State requirements that might conflict with it. Without any conflict, there could not be any implied preemption.

National Environmental Policy Act

NHTSA has analyzed this NPRM for the purposes of the National Environmental Policy Act (NEPA). The agency has determined that implementation of this action would not have any significant impact on the quality of the human environment.

Paperwork Reduction Act

Under the procedures established by the Paperwork Reduction Act of 1995, a person is not required to respond to a collection of information by a Federal agency unless the collection displays a valid OMB control number. This NPRM would not establish any new information collection requirements.

National Technology Transfer and Advancement Act

Under the National Technology Transfer and Advancement Act of 1995 (NTTAA, Pub. L. 104–113), ''all Federal agencies and departments shall use technical standards that are developed or adopted by voluntary consensus standards bodies, using such technical standards as a means to carry out policy objectives or activities determined by the agencies and departments.'' This proposal would harmonize FMVSS No. 109 with several voluntary consensus standards, including the T&RA 2008 Year Book standard,[8] the ETRTO standard,[9] and the JATMA standard,[10]

[7] 68 FR 38116; June 26, 2003, Docket NHTSA–03–15400; response to petitions for reconsideration, 71 FR 877, January 6, 2006, Docket 2005–23439; technical amendments, 72 FR 49207, August 28, 2007, Docket 2007–29083.

[8] The Tire & Rim Association, Inc. (T&RA), Year Book, 2008. Measuring Procedure for New Tires, at XIII.

[9] European Tyre and Rim Technical Organization (ETRTO), Standards Manual, 2005. Table 11.2, Temporary Use Spare Tyres—T Type, at P.22.

[10] The Japan Automobile Tyre Manufacturers Association, Inc. (JATMA), Year Book (Tyre Standards), 2008. Section G–5, ''Measuring Procedure for Tyres,'' Note 1, at 0–4.

all of which specify 60 psi or 420 kPa (or 4.2 bar) as the inflation pressure for measuring T-type tire dimensions. This proposal would also harmonize FMVSS No. 109 with ECE Regulation 30 and Japanese Safety Regulations, which currently require the physical dimensions test for T-type tires to be conducted at the tire's maximum permissible inflation pressure, 4.2 bar (420 kPa or 60 psi).

Civil Justice Reform

With respect to the review of the promulgation of a new regulation, section 3(b) of Executive Order 12988, ''Civil Justice Reform'' (61 FR 4729; Feb. 7, 1996), requires that Executive agencies make every reasonable effort to ensure that the regulation: (1) Clearly specifies the preemptive effect; (2) clearly specifies the effect on existing Federal law or regulation; (3) provides a clear legal standard for affected conduct, while promoting simplification and burden reduction; (4) clearly specifies the retroactive effect, if any; (5) adequately defines key terms; and (6) addresses other important issues affecting clarity and general draftsmanship under any guidelines issued by the Attorney General. This document is consistent with that requirement.

Pursuant to this Order, NHTSA notes as follows. The issue of preemption is discussed above in connection with E.O. 13132. NHTSA notes further that there is no requirement that individuals submit a petition for reconsideration or pursue other administrative proceeding before they may file suit in court.

Unfunded Mandates Reform Act

The Unfunded Mandates Reform Act of 1995 requires agencies to prepare a written assessment of the costs, benefits, and other effects of proposed or final rules that include a Federal mandate likely to result in the expenditure by State, local, or tribal governments, in the aggregate, or by the private sector, of more than $100 million annually (adjusted for inflation with base year of 1995). This NPRM would not result in expenditures by State, local, or tribal governments, in the aggregate, or by the private sector, in excess of $100 million annually.

Executive Order 13045

E.O. 13045 (62 FR 19885; Apr. 23, 1997) applies to any rule that: (1) Is determined to be ''economically significant'' as defined under E.O. 12866, and (2) concerns an environmental, health, or safety risk that NHTSA has reason to believe may have a disproportionate effect on children. This rulemaking is not subject to E.O. 13045 because it is not economically significant as defined in E.O. 12866.

Executive Order 13211

E.O. 13211 (66 FR 28355; May 18, 2001) applies to any rulemaking that: (1) Is determined to be economically significant as defined under E.O. 12866, and is likely to have a significantly adverse effect on the supply of, distribution of, or use of energy, or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action. This rulemaking is not subject to E.O. 13211.

Plain Language

E.O. 12866 and the President's memorandum of June 1, 1998, require each agency to write all rules in plain language. Application of the principles of plain language includes consideration of the following questions:

- Have we organized the material to suit the public's needs?
- Are the requirements in the rule clearly stated?
- Does the rule contain technical language or jargon that isn't clear?
- Would a different format (grouping and order of sections, use of headings, paragraphing) make the rule easier to understand?
- Would more (but shorter) sections be better?
- Could we improve clarity by adding tables, lists, or diagrams?
- What else could we do to make the rule easier to understand?

If you have any responses to these questions, please include them in your comments on this proposal.

Regulation Identifier Number (RIN)

The Department of Transportation assigns a regulation identifier number (RIN) to each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in April and October of each year. You may use the RIN contained in the heading at the beginning of this document to find this action in the Unified Agenda.

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 19477–19478).

VII. Public Participation

How Do I Prepare and Submit Comments?

Your comments must be written and in English. To ensure that your comments are correctly filed in the Docket, please include the docket number of this document in your comments. Your comments must not be more than 15 pages long.[11] We established this limit to encourage you to write your primary comments in a concise fashion. However, you may attach necessary additional documents to your comments. There is no limit on the length of the attachments. Please submit your comments by a method set forth in the **ADDRESSES** section at the beginning of this document.

Please also note that pursuant to the Data Quality Act, in order for substantive data to be relied upon and used by the agency, it must meet the information quality standards set forth in the OMB and DOT Data Quality Act guidelines. Accordingly, we encourage you to consult the guidelines in preparing your comments. OMB's guidelines may be accessed at *http://www.whitehouse.gov/omb/fedreg/reproducible.html.*

How Do I Submit Confidential Business Information?

If you wish to submit any information under a claim of confidentiality, you should submit three copies of your complete submission, including the information you claim to be confidential business information, to the Chief Counsel, NHTSA, at the address given above under **FOR FURTHER INFORMATION CONTACT**. When you send a comment containing information claimed to be confidential business information, you should include a cover letter setting forth the information specified in our confidential business information regulation. *See* 49 CFR part 512.

In addition, you should submit a copy, from which you have deleted the claimed confidential business information, to the Docket by one of the methods set forth above.

Will the Agency Consider Late Comments?

We will consider all comments received before the close of business on the comment closing date indicated above under **DATES**. To the extent possible, we will also consider comments received after that date. Therefore, if interested persons believe that any new information the agency places in the docket affects their

[11] *See* 49 CFR 553.21.

comments, they may submit comments after the closing date concerning how the agency should consider that information for the final rule.

If a comment is received too late for us to consider in developing a final rule (assuming that one is issued), we will consider that comment as an informal suggestion for future rulemaking action.

How Can I Read the Comments Submitted By Other People?

You may read the materials placed in the docket for this document (e.g., the comments submitted in response to this document by other interested persons) at any time by going to *http://www.regulations.gov*. Follow the online instructions for accessing the dockets. You may also read the materials at the DOT Docket at the street address listed above.

List of Subjects in 49 CFR Part 571

Imports, Motor vehicle safety, Motor vehicles, Rubber and rubber products, and Tires.

In consideration of the foregoing, we propose to amend 49 CFR part 571 to read as follows:

PART 571—FEDERAL MOTOR VEHICLE SAFETY STANDARDS

1. The authority citation for Part 571 continues to read as follows:

Authority: 49 U.S.C. 322, 20111, 30115, 30166 and 30177; delegation of authority at 49 CFR 1.50.

2. § 571.109 is amended by—

A. Removing the definition of CT in S3;

B. Revising S4.2.1(b), the introductory text of S4.3.4, and S4.4.1(b);

C. Redesignating Appendix A as ''Appendix to § 571.109,'' moving the appendix to the end of § 571.109 (following the tables to § 571.109), and revising the appendix; and

D. Revising Table I–C and Table II.

The revised and redesignated text, tables, and appendix read as follows:

§ 571.109 Standard No. 109; New pneumatic and certain specialty tires.

* * * * *

S4.2.1

* * * * *

(b) Its maximum permissible inflation pressure shall be either 32, 36, 40, or 60 psi, or 240, 280, 300, 340, or 350 kPa.

* * * * *

S4.3.4 If the maximum inflation pressure of a tire is 240, 280, 300, 340, or 350 kPa, then:

* * * * *

S4.4.1

* * * * *

(b) Contained in publications, current at the date of manufacture of the tire or any later date, of at least one of the following organizations:

Tire and Rim Association

The European Tyre and Rim Technical Organization

Japan Automobile Tire Manufacturers' Association, Inc.

Tyre and Rim Association of Australia

Associacao Latino Americana de Pneus e Aros (Brazil)

South African Bureau of Standards

* * * * *

TABLE 1–C—FOR RADIAL PLY TIRES

Size designation	Maximum permissible inflation							
	PSI			kPa				
	32	36	40	240	280	300	340	350
Below 160 mm:								
(in-lbs)	1,950	2,925	3,900	1,950	3,900	1,950	3,900	1,950
(joules)	220	330	441	220	441	220	441	220
160 mm or above:								
(in-lbs)	2,600	3,900	5,200	2,600	5,200	2,600	5,200	2,600
(joules)	294	441	588	294	588	294	588	294

* * * * *

TABLE II—TEST INFLATION PRESSURES

[Maximum permissible inflation pressure to be used for the following test]

Test type	psi				kPa				
	32	36	40	60	240	280	300	340	350
Physical dimensions	24	28	32	60	180	220	180	220	180
Bead unseating, tire strength, and tire endurance	24	28	32	52	180	220	180	220	180
High speed performance	30	34	38	58	220	260	220	260	220

* * * * *

Appendix to § 571.109

Persons requesting the addition of new tire sizes not included in S4.4.1 (b) organizations may, upon approval, submit five (5) copies of information and data supporting the request to the Vehicle Dynamics Division, Office of Crash Avoidance Standards, National Highway Traffic Safety Administration, 1200 New Jersey Ave SE., Washington, DC 20590.

The information should contain the following:

1. The tire size designation, and a statement either that the tire is an adition to a category of tires listed in the tables or that it is in a new category for which a table has not been developed.

2. The tire dimensions, including aspect ratio, size factor, section width, overall width, and test rim size.

3. The load-inflation schedule of the tire.

4. A statement as to whether the tire size designation and load inflation schedule has been coordinated with the Tire and Rim Association, the European Tyre and Rim Technical Organization, the Japan Automobile Tire Manufacturers' Association, Inc., the Tyre and Rim Association of Australia, the Associacao Latino Americana de Pneus e Aros (Brazil), or the South African Bureau of Standards.

5. Copies of test data sheets showing test conditions, results and conclusions obtained for individual tests specified in § 571.109.

6. Justification for the additional tire sizes.

Issued: October 22, 2009.

Stephen R. Kratzke,

Associate Administrator for Rulemaking.

[FR Doc. E9–26135 Filed 10–29–09; 8:45 am]

BILLING CODE 4910–59–P

Notices

Federal Register

Vol. 74, No. 209

Friday, October 30, 2009

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices of hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications and agency statements of organization and functions are examples of documents appearing in this section.

DEPARTMENT OF AGRICULTURE

Rural Housing Service

Rural Business-Cooperative Service

Notice of Request for Extension of a Currently Approved Information Collection

AGENCIES: Rural Housing Service (RHS), and Rural Business-Cooperative Service (RBS), USDA.

ACTION: Proposed collection; comments requested.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, this notice announces the intention of the above-named Agencies to request an extension for a currently approved information collection in support of debt settlement of Community Facilities and Direct Business Program Loans and Grants.

DATES: Comments on this notice must be received by December 29, 2009 to be assured of consideration.

FOR FURTHER INFORMATION CONTACT: For inquiries on the Information Collection Package, contact Beth Jones, Senior Loan Specialist, Community Programs, RHS, USDA, 1400 Independence Ave., SW., Mail Stop 0787, Washington, DC 20250–0787, Telephone (202) 720–1498, E-mail *beth.jones@wdc.usda.gov.*

SUPPLEMENTARY INFORMATION:

Title: 7 CFR part 1956, subpart C—''Debt Settlement—Community and Business Programs.''

OMB Number: 0575–0124.

Expiration Date of Approval: May 31, 2010

Type of Request: Extension of a currently approved information collection.

Abstract: The following Community and Direct Business Programs loans and grants are debt settled by this currently approved docket (0575–0124). The Community Facilities loan and grant program is authorized by Section 306 of the Consolidated Farm and Rural Development Act (7 U.S.C. 1926) to make loans to public entities, nonprofit corporations, and Indian tribes through the Community Facilities program for the development of essential community facilities primarily serving rural residents.

The Economic Opportunity Act of 1964, Title 3 (Pub. L. 88–452), authorizes Economic Opportunity Cooperative loans to assist incorporated and unincorporated associations to provide low-income rural families essential processing, purchasing, or marketing services, supplies, or facilities.

The Food Security Act of 1985, Section 1323 (Pub. L. 99–198), authorizes loan guarantees and grants to Nonprofit National Corporations to provide technical and financial assistance to for-profit or nonprofit local businesses in rural areas.

The Business and Industry program is authorized by Section 310 B (7 U.S.C. 1932) (Pub. L. 92.419, August 30, 1972) of the Consolidated Farm and Rural Development Act to improve, develop, or finance business, industry, and employment and improve the economic and environmental climate in rural communities, including pollution abatement control.

The Consolidated Farm and Rural Development Act, Section 310 B(c) (7 U.S.C. 1932(c)), authorizes Rural Business Enterprise Grants to public bodies and nonprofit corporations to facilitate the development of private businesses in rural areas.

The Consolidated Farm and Rural Development Act, Section 310 B(f)(i) (7 U.S.C. 1932(c)), authorized Rural Cooperative Development Grants to nonprofit institutions for the purpose of enabling such institutions to establish and operate centers for rural cooperative development.

The purpose of the debt settlement function for the above programs is to provide the delinquent client with an equitable tool for the compromise, adjustment, cancellation, or charge-off of a debt owned to the Agency.

The information collected is similar to that required by a commercial lender in similar circumstances.

Information will be collected by the field offices from applicants, borrowers, consultants, lenders, and attorneys.

Failure to collect information could result in improper servicing of these loans.

Estimate of Burden: Public reporting burden for this collection of information is estimated to average 5 hours per response.

Respondents: Public bodies and nonprofit organizations.

Estimated Number of Respondents: 15.

Estimated Number of Responses per Respondent: 1.

Estimated Number of Responses: 82.

Estimated Total Annual Burden on Respondents: 372 hours.

Copies of this information collection can be obtained from Linda Watts Thomas, Regulations and Paperwork Management Branch, (202) 692–0226.

Comments:

Comments are invited on: (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information will have practical utility; (b) 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) ways to enhance the quality, utility, and clarity of the information to be collected; and (d) ways to minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology. Comments may be sent to Linda Watts Thomas, Regulations and Paperwork Management Branch, U.S. Department of Agriculture, Rural Development, STOP 0742, 1400 Independence Ave., SW., Washington, DC 20250. All responses to this notice will be summarized and included in the request for OMB approval. All comments will also become a matter of public record.

Dated: October 23, 2009.

Tammye Treviño,

Administrator, Rural Housing Service.

Dated: October 23, 2009.

Judith A. Canales,

Administrator, Rural Business-Cooperative Service.

[FR Doc. E9–26153 Filed 10–29–09; 8:45 am]

BILLING CODE 3410–XV–P

DEPARTMENT OF AGRICULTURE

Forest Service

California Recreation Resource Advisory Committee

AGENCY: Pacific Southwest Region, Forest Service, U.S. Department of Agriculture.

ACTION: Request for applications.

SUMMARY: Applications are being sought for certain positions on the California Recreation Resource Advisory Committee. New members will be appointed by the Secretary of Agriculture and serve three year terms. Appointments will begin July 2010 when current member appointments expire. One member is being sought to represent each of the following interests: (1) Winter Non-Motorized Recreation, (2) Summer Motorized Recreation, (3) Summer Non-Motorized Recreation, (4) Non-Motorized Outfitters and Guides, (5) Local Environmental Groups, (6) State Tourism, (7) Indian Tribes, and (8) Local Government.

The public is invited to submit applications for these positions. Current members who have only served one term may reapply. Application packages can be obtained at *http://www.fs.fed.us/passespermits/rrac-application.shtml* or by e-mailing *R5rrac@fs.fed.us.* Interested parties may also contact Frances Enkoji, US Forest Service, at 707–562–8846.

DATES: All applications must be received by December 11, 2009. This timeframe can be extended if officials do not receive applications for the needed positions.

ADDRESSES: Interested parties may submit applications by mail to Frances Enkoji, US Forest Service, 1323 Club Drive, Vallejo, CA 94592.

FOR FURTHER INFORMATION CONTACT: Anyone wanting further information regarding the California Recreation Resource Advisory Committee may contact Marlene Finley, Designated Federal Official, Pacific Southwest Region Recreation RAC, 1323 Club Drive, Vallejo, CA 94592; 707–562–8856.

SUPPLEMENTARY INFORMATION: The Federal Lands Recreation Enhancement Act (REA), signed December 2004, requires that the Forest Service and Bureau of Land Management provide Recreation RACs with an opportunity to make recommendations to the two agencies on implementing or eliminating standard amenity fees; expanded amenity fees; and noncommercial special recreation permit fees; expanding or limiting the recreation fee program; and fee level changes. Each Recreation RAC consists of 11 members appointed by the Secretary.

Nomination Information: Applicants must complete an AD–755 form (Advisory Committee or Search and Promotion Background Information) and provide a narrative that addresses the following:

(1) What group or perspective they represent and how they are qualified to represent that group;

(2) Why they want to serve on the committee and what they can contribute;

(3) Their past experience in working successfully as part of a collaborative group.

Letters of recommendation are welcome but not required. Applicants do not need to live in a state within a particular Recreation RAC's area of jurisdiction nor live in a state in which Forest Service managed lands are located. Application packages, including evaluation criteria and AD–755 are available at *http://www.fs.fed.us/passespermits/rracapplication.shtml* or by contacting the Pacific Southwest Region as identified in this notice. Completed application packages must be received by December 11, 2009. Additional information about the California Recreation RAC can be found at *http://www.fs.fed.us/r5/passes/rrac* or about recreation fees at *http://www.fs.fed.us/passespermits/about-rec-fees.shtml.* The Forest Service will also work the Governor and local officials to identify potential applicants. The Forest Service and Bureau of Land Management will review applications and prepare a list of qualified applicants from which the Secretary shall appoint both members and alternates. The alternate will become a participating member of the Recreation RAC only if the member for whom the alternate is appointed to replace leaves the committee permanently. Recreation RAC members serve without pay but are reimbursed for travel and per diem expenses for regularly scheduled meetings. All Recreation RAC meetings are open the public and an open public forum is part of each meeting. Meeting dates and time will be determined by agency officials in consultation with the Recreation RAC members.

Dated: October 21, 2009.

Marlene Finley,

Designated Federal Official, Recreation RAC, Pacific Southwest Region.

[FR Doc. E9–26086 Filed 10–29–09; 8:45 am]

BILLING CODE 3410–11–M

DEPARTMENT OF AGRICULTURE

Rural Utilities Service

Minnkota Power Cooperative, Inc.: Notice of Intent To Hold Public Scoping Meetings and Prepare an Environmental Assessment

AGENCY: Rural Utilities Service, USDA.

ACTION: Notice of intent to hold public scoping meetings and prepare an Environmental Assessment.

SUMMARY: The Rural Utilities Service (RUS) intends to hold public scoping meetings and prepare an Environmental Assessment with Scoping (EA) to meet its responsibilities under the National Environmental Policy Act (NEPA) and 7 CFR part 1794 in connection with potential impacts related to a proposed project by Minnkota Power Cooperative, Inc. (Minnkota). The proposed Center to Grand Forks Transmission Line Project (proposed action) consists of: the construction of approximately 260 miles of 345 kilovolt (kV) transmission line from Center to Grand Forks, North Dakota; upgrades at the Center 345 kV substation; upgrades at the Square Butte 230 kV Substation; an additional 230 kV tie line; and upgrades at the Prairie Substation and fiber optic regeneration stations. Minnkota is requesting that RUS provide financial assistance for the proposed action.

DATES: RUS will conduct public scoping meetings in an open house format to provide information and solicit comments for the preparation of the EA. Scoping meetings will be held on the following dates: Grand Forks, ND, Alerus Center, Eagle Room 10, 1200 S. 42nd St., Monday, November 16, 2009, 5–8 p.m.; Cooperstown, ND, Cooperstown City Hall, 611 9th St., Tuesday, November 17, 2009, 10 a.m.–1 p.m.; Carrington, ND, Chieftain Conference Center, Tee Pee Room 60, 4th Avenue S., Tuesday, November 17, 2009, 5:00–8:00 pm; McClusky, ND, McClusky Community Hall, 117 Avenue B North, Wednesday, November 18, 2009, 10 a.m.–1 p.m.; Wilton, ND, City of Wilton Memorial Hall, 105 Dakota Avenue, Wednesday, November 18, 2009, 5–8 p.m.; and Center, ND, Center Civic Center Building, 312 N Lincoln Ave., Thursday, November 19, 2009, 5–8 p.m.

ADDRESSES: To send comments or request additional information, contact: Mr. Dennis Rankin, Environmental Protection Specialist, USDA, Rural Utilities Service, 1400 Independence Avenue, SW., Stop 1571, Washington, DC 20250–1571, telephone: (202) 720–1953 or *e-mail:*

dennis.rankin@wdc.usda.gov. An Alternative Evaluation Study (AES) and a Macro Corridor Study (MCS) has been prepared for the proposed project. All documents are available for public review prior to and during the public scoping meetings. The reports are available at the RUS address provided in this notice and on the agency's Web site at: *http://www.usda.gov/rus/water/ees/ea.htm*., the offices of Minnkota Power Cooperative, Inc. and their Web site at: *http://www.minnkota.com*; and the following repositories: Aneta Public Library, 11995 19th St., Aneta, ND 58212–0088; Bismarck's Veterans Memorial Library, 515 N. 5th St., Bismarck, ND 58501–4057; Oliver County Auditor, 115 West Main, Center, ND 58530; City of Carrington Library, 55 9th Ave., Carrington, ND 58421–2017; Griggs County Library, 902 Burrel Ave., Cooperstown, ND 58425–0546; Goodrich Public Library, 122 McKinley Ave., Goodrich, ND 58444–0175; Grand Forks Library, 2110 Library Circle, Grand Forks, ND 58201–6324; Harvey Public Library, 119 10th St., Harvey, ND 58341–1531; Mayville Library, 52 Center Ave., Mayville, ND 58257–1299; Sheridan County Auditor, 215 East 2nd St., McClusky, ND 58356–1510; New Rockford Public Library, 811 First Ave. N, New Rockford, ND 58356–1510; Turtle Lake Public Library, 107 Eggert St., Turtle Lake, ND 58575–0540; Washburn Public Library, 705 Main Ave., Washburn, ND 58577–0637; and Northwood Public Schools and City Library, 300 35th St., Northwood, ND 58267.

SUPPLEMENTARY INFORMATION: The purpose of the proposed action is to reallocate energy presently transmitted on an existing direct current (DC) line to the proposed 345 kV line. Currently, the output from the Milton R. Young Generation Station Unit 2 (Young 2) is purchased under contract by Minnkota and Minnesota Power; each utility receives approximately 50 percent of the output. Electricity generated by Young 2 flows over a dedicated DC, 465-mile transmission line from Center, North Dakota to Duluth, Minnesota, where it is converted back to alternating current (AC) for further transmission into the Minnesota Power and Minnkota service areas. Minnesota Power will take 100 percent ownership of the existing DC line and DC/AC conversion facilities in early 2010; the DC line will be used to deliver wind energy. In 2013, Minnkota will receive increasing allocations of Young 2 output until the year 2026 when Minnkota will purchase 100 percent of the Young 2 output. With no continuous capacity available to Minnkota on the HVDC system, the power needs be moved over the AC transmission system to Minnkota's service territory.

Minnkota is seeking financing from RUS for its ownership of the proposed project. Before making a decision to provide financing for the proposed project, RUS is required to conduct an environmental review under NEPA in accordance with RUS's Environmental Policies and Procedures (7 CFR Part 1794). Government agencies, private organizations, and the public are invited to participate in the planning and analysis of the proposed action. Representatives from RUS and Minnkota will be available at the scoping meetings to discuss the environmental review process, describe the proposed action, discuss the scope of environmental issues to be considered, answer questions, and accept comments. RUS will use comments and input provided in the preparation of the Draft EA. If RUS finds, based on the EA, that the proposed action will not have a significant effect on the quality of the human environment, RUS will prepare a Finding of No Significant Impact (FONSI). Public notification of the FONSI would be published in the **Federal Register** and in newspapers with circulation in the project area. RUS may take its final action on proposed actions requiring an EA (§ 1794.23) any time after publication of applicant notices that a FONSI has been made and any required review period has expired. When substantive comments are received on the EA, RUS may provide an additional period (15 days) for public review following the publication of its FONSI determination. Final action will not be taken until this review period has expired. Where appropriate to carry out the purposes of NEPA, RUS may impose, on a case-by-case basis, additional requirements associated with the preparation of an EA. If at any point in the preparation of an EA, RUS determines that the proposed action will have a significant effect on the quality of the human environment, the preparation of an Environmental Impact Statement will be required. Any final action by RUS related to the proposed action will be subject to, and contingent upon, compliance with all relevant Federal, State, and local environmental laws and regulations and completion of the environmental review requirements as prescribed in RUS's Environmental Policies and Procedures (7 CFR Part 1794).

Dated: October 23, 2009.

Mark S. Plank,

Director, Engineering and Environmental Staff, Rural Utilities Service.

[FR Doc. E9–26146 Filed 10–29–09; 8:45 am]

BILLING CODE P

DEPARTMENT OF AGRICULTURE

Forest Service

Shasta Trinity National Forest, South Fork Management Unit, California Rattlesnake Fuel Reduction and Forest Health Project

AGENCY: Forest Service, USDA.

ACTION: Notice of intent to prepare an environmental impact statement.

SUMMARY: The Hayfork District of the Shasta Trinity National Forest is proposing to use vegetation treatments to reduce risks from fire, improve forest health, and provide forest products on approximately 6,028 acres within the Rattlesnake watershed on the South Fork Management Unit of the Shasta Trinity National Forest. The active management needed in the Rattlesnake Fuel Reduction and Forest Health Project (Rattlesnake project) area to reduce fuels and stocking levels through thinning requires the removal of trees and biomass, some of which have commercial value. An estimated 33 million board feet of merchantable sawtimber, and an estimated 35,092 bone dry tons of biomass are expected to be removed. Providing wood products to meet regional and national needs is consistent with Forest Plan goals, standards and guidelines. The initial economic analysis shows that the average diameter and quantity of the material treated under this project would generally be insufficient to support a viable timber sale in today's market. The Forest Service will analyze these vegetation treatments within the constraints of the Shasta Trinity National Forest Land and Resource Management Plan, 1995.

The proposed Rattlesnake project is in the vicinity of the Post Mountain and Forest Glen communities in southern Trinity County, California. The project area is within portions of the Wildland Urban Interface (WUI) boundaries for both of these communities and within the Hayfork Adaptive Management Area (AMA), and Management Area 19, Indian Valley/Rattlesnake, of the Shasta-Trinity Land and Resource Management Plan (USFS 1995, p. 4–64 & 4–65).

The project includes acreage in Township 1 North, Range 7 East, Sections 25 and 36, Township 1 North, Range 8 East, Sections 19–21, and 28–

33, Township 1 South, Range 7 East, Sections 1 and 12, Township I South, Range 8 East, Sections 4–9, 16–21 and 28–29, Humboldt Meridian; Township 30 North, Range 12 West, Sections 35, 34, 32, Township 29 North, Range 12 West, Sections 1–19, 22, 23, Township 29 North, Range 11 West, Sections 29, and 31–32, Mount Diablo Meridian. The project is located in Trinity County, 10 air miles south of Hayfork, California and 3 air miles east of Post Mountain, California.

DATES: Comments must be received no later than 30 days after publication of this notice in the **Federal Register**. The draft environmental impact statement is expected in the spring of 2010 and the final environmental impact statement is expected the winter of 2010.

ADDRESSES: Please send written comments to Sandy Mack, TEAMS USFS Enterprise Unit, 1801 N. First, Hamilton, MT 59840–3114. Electronic comments may be submitted via e-mail to: *comments-pacificsouthwest-shasta-trinity-yollabolla-hayfork@fs.fed.us* with ''Rattlesnake Project'' as the subject.

Comments received in response to this solicitation, including names and addresses of those who comment, will be part of the public record for this proposed action. Comments submitted anonymously will be accepted and considered; however, anonymous comments will not provide the respondent with standing to participate in subsequent administrative review or judicial review.

FOR FURTHER INFORMATION CONTACT: Sandy Mack, Project Team Leader, TEAMS USFS Enterprise Unit, 1801 N. First, Hamilton, MT 59840. Phone (406) 375–2638. Or contact Donna Harmon, South Fork Management Unit District Ranger, P.O. Box 159, Hayfork, CA 96041, (530) 628–5227. Information about this project is posted on the forest Web site (*http://www.fs.fed.us/r5/shastatrinity/projects*).

Individuals who use telecommunication devices for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339 between 8 a.m. and 8 p.m., Eastern Time, Monday through Friday.

SUPPLEMENTARY INFORMATION:

Purpose and Need for Action

The purpose and need for the Rattlesnake project is reflected in the following three interrelated objectives:

- Reduce hazardous fuel conditions to reduce the potential for adverse impacts from wildfire to Forest System land, including within riparian and late successional reserves, and neighboring private land.
- Improve forest health and resiliency, including within riparian and late successional reserves.
- Provide timber products to help support the economic structure of local communities, and supply regional and national needs, when the materials removed to meet the first two objectives have commercial value.

The Rattlesnake project area overlaps the Trinity Pines/Post Mountain and the Forest Glen wildland urban interfaces, and is within five miles of Peanut to the north and Wildwood to the east. These dispersed residential communities are identified in the Trinity County Community Wildfire Protection Plan as having values ''at risk'' from wildfire. The town of Hayfork is approximately ten miles north of the project area. Both the National Fire Plan and the Ten-Year Comprehensive Strategy for Reducing Wildiand Fire Risks to Communities and the Environment place a priority on working collaboratively within communities in the WUI to reduce their risk from large-scale wildfire.

The project area receives high concentrations of dry lightning, as was experienced extensively in 2008. The Trinity County wildfires of 2008 burned 266,157 acres in three major complexes. It resulted in the death of 10 wildland firefighters, and required 15 mandatory evacuation orders for over 1,400 homes. The Rattlesnake project area straddles Highway 36 which serves as a main ingress, egress route for residents during a fire. The highway also provides added potential for human caused fires.

In addition to the neighboring residential communities at risk, there are forest resources in the project area that are also at risk from uncharacteristically severe fire. These resources include non-perennial stream corridors, late successional reserves, and high investment resources, such as tree plantations and the Bridgeville-Cottonwood 60 KV transmission line. Two roadless areas cross into the project area on the western edge (South Fork) and to the southern edge (Chinquapin) of the project. The Shasta-Trinity National Forest Late Successional Reserve Assessment identifies the potential for large, high intensity fire as a primary concern within the South Fork Late Successional Reserve (RC–330) which enters into the southern tip of the project area.

The Rattlesnake project is designed to strategically connect with fuel treatments implemented through the Post Mountain Stewardship project, and those planned in the Salt Timber Harvest and Fuel Hazard Reduction project. These projects are similar to the Rattlesnake project, but are not connected actions.

Over half of the Rattlesnake project area, 55 percent, currently has moderate to high potential for crown fires. This is significant because crown fires normally are highly destructive, difficult to control, and present the greatest safety hazard to firefighters and the public. The desired condition is for fuels in the project area to support a surface fire, rather than a crown fire.

Approximately 57 percent of the Rattlesnake project area would have control problems in the event of a fire because of the current fuel conditions, measured by projected flame lengths greater than eight feet. Control efforts by hand crews would likely be effective in only 14 percent of the project area and would be ineffective in the remaining 86 percent of the area. The desired condition is for flame lengths to be four feet or less in the project area so that direct attack with hand crews would be possible. This is particularly important given the project area's proximity to neighboring communities. The Shasta-Trinity National Forest Late Successional Reserve Assessment also identifies a desired condition of flame lengths less than four feet.

The project area needs fuel breaks to provide firefighters with a strategic place to defend against an oncoming fire.

Currently, stands in the Rattlesnake project area are overstocked. These dense stands contain excessive surface fuels, ladder fuels consisting of dense midstory and understory trees and shrubs, and continuous canopies of hardwood and conifer overstory trees. Competition for limited water, nutrients and sun in many highly stocked timber stands in the Rattlesnake project area has reduced the vigor, growth and resiliency to insects and disease of mixed conifer species. Thinning to accelerate growth is a priority, particularly in younger mid-successional stands in the South Fork Late Successional Reserve. The desired condition is for overstocked stands to be thinned to a relative stand density approximately 35% to 55%.

The purpose and need for the Rattlesnake project are consistent with Management Plan Goals #3, #10, #11, #34, #35, #36, #39, and #40 Shasta-Trinity Land and Resource Management Plan (USFS 1995, p. 4–5 and 4–6).

Proposed Action

The Rattlesnake project proposes vegetative management on a total of 6,028 acres in order to improve forest health, reduce risks from fire, and provide forest products. Approximately

396 acres of brush field would be burned and 5,540 acres would be thinned. Thinning would include:

- Thin from below: 3,610 acres,
- Hand thin to 10 inch diameter at breast height (dbh): 92 acres,
- Shaded fuel break: 1,707 acres of thin from below in a shaded fuel break,
- Shaded fuel break—thin to 8 inch dbh: 135 acres within perennial riparian reserves that intersect fuel breaks, but outside of the equipment exclusion zone,
- Plantation pre-commercial thin: 88 acres.

Sub-merchantable fuel would be reduced in all treatment units to desirable levels of between 5 and 10 tons of downed material per acre depending on the Forest Plan land allocation for the area.

Approximately 6.7 miles of new temporary roads would be needed to access units. Approximately 65.6 miles of system roads will require pre-haul maintenance, such as blading. Approximately 13.5 miles of system roads will require more earthwork and sight distance clearing before they can be safely used as haul roads. Approximately 2.4 miles of unclassified routes, would require brushing and re-shaping for use with this project, and then decommissioned after use. Approximately 21 miles of system road and 7 miles of unclassified routes would be decommissioned after use for this project. Treatments are expected to produce 33 million board feet (mmbf) of potentially merchantable saw timber and 35,092 tons of biomass.

Responsible Official

J. Sharon Heywood, Forest Supervisor, Shasta-Trinity National Forest.

Nature of Decision To Be Made

The Forest Supervisor will decide whether to implement the proposed action, take an alternative action that meets the purpose and need, or take no action.

Scoping Process—Public Comment

This notice of intent initiates the scoping process, which guides the development of the environmental impact statement. The project will be included in the Shasta-Trinity National Forest's quarterly schedule of proposed actions (SOPA). Information on the proposed action will also be posted on the forest Web site (*http://www.fs.fed.us/r5/shastatrinity/projects*) and advertised in the Record Searchlight—a local newspaper.

It is important that reviewers provide their comments at such times and in such manner that they are useful to the agency's preparation of the environmental impact statement. Therefore, comments should be provided prior to the close of the comment period and should clearly articulate the reviewer's concerns and contentions. The submission of timely and specific comments can affect a reviewer's ability to participate in subsequent administrative appeal or judicial review.

Dated: October 21, 2009.

Donna F. Harmon,

South Fork Management Unit District Ranger, Shasta-Trinity National Forest.

[FR Doc. E9–26064 Filed 10–29–09; 8:45 am]

BILLING CODE 3410–11–M

DEPARTMENT OF AGRICULTURE

Forest Service

Custer County Resource Advisory Committee

AGENCY: Forest Service, USDA.

ACTION: Notice of meeting.

SUMMARY: The Custer County Resource Advisory Committee will meet in Custer, South Dakota. The purpose of the meeting is review and selection of project proposals to be funded by the 2009 allocation.

DATES: The meeting will be held November 17, 2009 at 5:30 p.m.

ADDRESSES: The meeting will be held at the Black Hills National Forest Supervisors Office. Written comments should be sent to Lynn Kolund at 330 Mount Rushmore Road, Custer, South Dakota 57730. Comments may also be sent via e-mail to *lkolund@fs.fed.us,* or via facsimile to 605–673–5461.

All comments, including names and addresses when provided, are placed in the record and are available for public inspection and copying. The public may inspect comments received at 330 Mount Rushmore Road, Custer, South Dakota. Visitors are encouraged to call ahead to 605–673–4853 to facilitate entry into the building.

FOR FURTHER INFORMATION CONTACT: Lynn Kolund, Designated Federal Official, Hell Canyon Ranger District, 605–673–4853.

Individuals who use telecommunication devices for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339 between 8 a.m. and 8 p.m., Eastern Standard Time, Monday through Friday.

SUPPLEMENTARY INFORMATION: The meeting is open to the public. Council discussion is limited to Forest Service staff and Council members. However, persons who wish to bring 2009 Project Proposal matters to the attention of the Council may file written statements with the Council staff before or after the meeting. Public input sessions will be provided and individuals who made written requests by November 13, 2009 will have the opportunity to address the Council at the November 17, 2009 session.

Dated: October 26, 2009.

Lynn Kolund,

Designated Federal Official.

[FR Doc. E9–26157 Filed 10–29–09; 8:45 am]

BILLING CODE 3410–11–M

DEPARTMENT OF COMMERCE

National Institute of Standards and Technology

Proposed Information Collection; Comment Request; Malcolm Baldrige National Quality Award and Examiner Applications

AGENCY: National Institute of Standards and Technology (NIST).

ACTION: Notice.

SUMMARY: The Department of Commerce, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995.

DATES: Written comments must be submitted on or before December 21, 2009.

ADDRESSES: Direct all written comments to Diana Hynek, Departmental Paperwork Clearance Officer, Department of Commerce, Room 7845, 14th and Constitution Avenue, NW., Washington, DC 20230 (or via the Internet at *dHynek@doc.gov).*

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the information collection instrument and instructions should be directed to Pamela P. Wong, Baldrige National Quality Program, Administration Building, Room 615, 100 Bureau Drive, Stop 1020, National Institute of Standards and Technology, Gaithersburg, Maryland 20899–1020; telephone (301) 975–4504, fax (301) 948–3716, e-mail *pamela.wong@nist.gov.*

SUPPLEMENTARY INFORMATION:

I. Abstract

The Department of Commerce is responsible for the Baldrige National Quality Program and the Malcolm Baldrige National Quality (BNQP) Award. Directly associated with this Award is the Board of Examiners, an integral part of the Baldrige National Quality Program. NIST manages the Baldrige Program. An applicant for the Malcolm Baldrige National Quality Award is required to perform two steps: (1) The applicant organization certifies that it meets eligibility requirements; and (2) the applicant organization prepares and completes an application form and the application process. The Malcolm Baldrige National Quality Award Program Office will assist with or offer advice on any questions or issues that the applicant may have concerning the eligibility process or in completing the self-certification forms. NIST will use the application package to assess and provide feedback on the applicant's quality and performance practices.

The application to be a member of the Board of Examiners is a one-step process. Each year the Award Program recruits highly skilled experts in the fields of manufacturing, service, small business, health care, education, and nonprofit, the six Award eligibility categories, to evaluate the applications that the Program receives. Examiners serve for a one-year term; participation on the board is entirely voluntary.

II. Method of Collection

Award applicants must comply in writing according to the Baldrige Award Application Forms available at *http://www.baldrige.nist.gov/Award_Application.htm.* The application for the 2009 Board of Examiners can be found at *http://www.baldrige.nist.gov/Examiner_Application.htm.* It is submitted electronically.

III. Data

OMB Control Number: 0693–0006.

Form Number: None.

Type of Review: Regular submission.

Affected Public: Business or other for-profit organizations; not-for-profit institutions; and individuals or households.

Estimated Number of Respondents: 900. (100 Applicants for the Malcolm Baldrige Award, 800 Applicants for the Board of Examiners).

Estimated Time per Response: 74 hours for Applications for the Malcolm Baldrige Quality Award, and 1 hour for the Applications for the Board of Examiners.

Estimated Total Annual Burden Hours: 8,200

Estimated Total Annual Cost to Public: $125,000 ($1,250 for each of the 100 Awardees—costs are for duplication and mailing).

IV. Request for Comments

Comments are invited on: (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden (including hours and cost) of the proposed collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; and (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology.

Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval of this information collection; they also will become a matter of public record.

Dated: October 27, 2009.

Gwellnar Banks,

Management Analyst, Office of the Chief Information Officer.

[FR Doc. E9–26155 Filed 10–29–09; 8:45 am]

BILLING CODE 3510–13–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XQ61

Atlantic Highly Migratory Species (HMS); Atlantic Shark Management Measures; 2010 Research Fishery

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

ACTION: Notice of intent; request for applications.

SUMMARY: NMFS announces its request for applications for the 2010 shark research fishery from commercial shark fishermen with a directed or incidental permit. The shark research fishery allows for the collection of fishery-dependent data for future stock assessments while also allowing NMFS and commercial fishermen to conduct cooperative research to meet the shark research objectives for the Agency. The only commercial vessels authorized to land sandbar sharks are those participating in the shark research fishery. Shark research fishery permittees may also land non-sandbar large coastal sharks (LCS), small coastal sharks (SCS), and pelagic sharks. Commercial vessels not participating in the shark research fishery may only land non-sandbar LCS, SCS, and pelagic sharks. Commercial shark fishermen who are interested in participating in the shark research fishery need to submit a completed Shark Research Fishery Permit Application in order to be considered. Generally, these permits will be valid through December 31, 2010, unless otherwise specified, subject to the terms and conditions of individual permits.

DATES: Shark Research Fishery Applications must be received no later than 5 p.m., local time, on November 30, 2009.

ADDRESSES: Please submit completed applications to the HMS Management Division at:

- Mail: Attn: Guy DuBeck, HMS Management Division (F/SF1), NMFS, 1315 East-West Highway, Silver Spring, MD 20910.
- Fax: (301) 713–1917

For copies of the Shark Research Fishery Permit Application, please write to the HMS Management Division at the address listed above, or call (301) 713–2347 (phone), or (301) 713–1917 (fax). Copies of the Shark Research Fishery Application are also available at the HMS website at *http://www.nmfs.noaa.gov/sfa/hms/index.htm.*

FOR FURTHER INFORMATION CONTACT: Karyl Brewster-Geisz or Guy DuBeck, at (301) 713–2347 (phone) or (301) 713–1917 (fax).

SUPPLEMENTARY INFORMATION: The Atlantic shark fisheries are managed under the authority of the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act). The Consolidated HMS Fishery Management Plan (FMP) is implemented by regulations at 50 CFR Part 635.

The final rule for Amendment 2 to the Consolidated HMS FMP (73 FR 35778, June 24, 2008, corrected at 73 FR 40658, July 15, 2008) established, among other things, a shark research fishery to maintain time series data for stock assessments and to meet NMFS' research objectives. The shark research fishery also allows selected commercial fishermen the opportunity to earn revenue from selling more sharks, including sandbar sharks, than allowed outside of the commercial shark fishery. Only the commercial shark fishermen selected to participate in the shark research fishery are authorized to land/

harvest sandbar sharks subject to the sandbar quota available each year. The base quota is 87.9 mt dw per year through December 31, 2012, although this number may be reduced in the event of overharvests, if any. The selected shark research fishery permittees will also have access to the non-sandbar LCS, SCS, and pelagic shark quotas. Commercial fishermen not participating in the shark research fishery may land non-sandbar LCS, SCS, and pelagic sharks subject to retention limits and quotas per 50 CFR 635.24 and 635.27, respectively.

In 2009, selected vessels were allowed a trip limit of 45 sandbar sharks and 33 non-sandbar large coastal sharks. The vessels participating in the shark research fishery fished an average of 2 trips per month. The 2010 trip limits and number of trips per month will depend on the number of selected vessels, available quota, and objectives of the research fishery. Vessels selected for 2010 may not all have the same retention limit.

In order to participate in the shark research fishery, commercial shark fishermen need to submit a completed Shark Research Fishery Application showing the vessel and owner(s) meet the specific criteria outlined below.

Research Objectives

Each year, NMFS will determine the research objectives for the upcoming shark research fishery. The research objectives are developed by a shark board, which is comprised of representatives within NMFS including representatives from the Southeast Fisheries Science Center (SEFSC) Panama City Laboratory, Northeast Fisheries Science Center (NEFSC) Narragansett Laboratory, the Southeast Regional Office, Protected Species Division (SERO\PSD), and the HMS Management Division. The research objectives for 2010 are similar to the research objectives for 2009, and the shark board based them on the Southeast Data, Assessment and Review (SEDAR) 11, 2005/2006 LCS stock assessment. These research objectives include:

- Collect reproductive and age data from sandbar sharks throughout the calendar year;
- Collect reproductive and age data for Gulf of Mexico blacktip sharks for determination of the reproductive cycle (i.e., annual or biennial frequency);
- Collect reproductive and age data from all species of sharks for additional species-specific assessments;
- Monitor the size distribution of sandbar sharks and other species captured in the fishery;
- Continue on-going tagging programs for identification of migration corridors and stock structure;
- Maintain time-series of abundance from previously derived indices for the shark BLL observer program;
- Acquire fin-clip samples of all species for genetic analysis;
- Attach satellite archival tags to endangered smalltooth sawfish to provide information on critical habitat and preferred depth, consistent with ESA requirements for such tagging under the SEFSC observer program take permit obtained through the 2008 Section 7 Consultation and Biological Opinion (BiOp) for the Continued Authorization of Shark Fisheries (Commercial Shark Bottom Longline, Commercial Shark Gillnet and Recreational Shark Handgear Fisheries) as Managed under the Consolidated Fishery Management Plan for Atlantic Tunas, Swordfish, and Sharks (Consolidated HMS FMP), including Amendment 2 to the Consolidated HMS FMP (F/SER/2007/05044);
- Attach satellite archival tags to prohibited dusky sharks to provide information on daily and seasonal movement patterns, and preferred depth; and,
- Evaluate the effects of controlled gear experiments in order to determine the effects of potential hook changes to prohibited species interactions and fishery yields.

In the 2010 shark research fishery, NMFS would like to examine the size distribution of sandbar sharks and other species captured in the Mid-Atlantic shark time/area closure off the coast of North Carolina from January 1 through July 31. The Mid-Atlantic shark time-area closure has been in effect since 2005 and NMFS would like to collect baseline data in the closed area under current conditions. Also, NMFS would like to collect data to examine the effectiveness of existing area closures to meet current conservation and harvesting goals.

Additionally, some objectives were derived from the need for tagging studies, collection of genetic material, and controlled bottom longline (BLL) experiments to assess the impact of hook changes. The shark board decided to use the same objectives given for research in 2009.

Selection Criteria

Shark Research Fishery Permit Applications will only be accepted from commercial shark fishermen that hold a current directed or incidental limited access permit. While incidental permit holders are welcome to submit an application, to ensure that an appropriate number of sharks are taken to meet the research objectives for this year, NMFS will be giving priority to directed permit holders. As such, qualified incidental permit holders will only be selected if there are not enough qualified directed permit holders to meet research objectives.

The Shark Research Fishery Permit Application includes, but is not limited to, a request for the following information: type of commercial shark permit possessed; past participation in the commercial shark fishery (not including sharks caught for display); past involvement and compliance with HMS observer programs per 50 CFR 635.7; past compliance with HMS regulations at 50 CFR part 635; availability to participate in the shark research fishery; ability to fish in the regions and season requested; ability to attend necessary meetings regarding the objectives and research protocols of the shark research fishery; and ability to carry out the research objectives of the Agency. An applicant that has been charged criminally or civilly (i.e., issued a Notice of Violation and Assessment (NOVA) or Notice of Permit Sanction) for any HMS-related violation will not be considered for participation in the shark research fishery. In addition, applicants who were selected to carry an observer in the previous two years for any HMS fishery, but failed to communicate with NMFS observer programs in order to arrange the placement of an observer before commencing any fishing trip that would have resulted in the incidental catch or harvest of any Atlantic HMS, per 50 CFR 635.7, will not be considered for participation in the 2010 shark research fishery. Applicants who were selected to carry an observer in the previous two years for any HMS fishery and failed to comply with all the observer regulations per 50 CFR 635.7, including failure to provide adequate sleeping accommodations per 50 CFR 635.7(e)(1), a sufficiently sized survival craft per 50 CFR 600.746(f)(6), or failure to pass a USCG safety examination per 50 CFR 600.746(c)(2) will also not be considered. Exceptions will be made for vessels that were selected for HMS observer coverage but did not fish in the quarter when selected. Applicants that do not possess a valid Unites States Coast Guard (USCG) safety inspection decal when the application is submitted will not be considered. Applicants that have been non-compliant with any of the HMS observer program regulations in the previous two years, as described above, may be eligible for future participation in shark research fishery activities by demonstrating two subsequent years of compliance with observer regulations at 50 CFR 635.7.

Selection Process

The HMS Management Division will review all submitted applications that are deemed complete and develop a list of qualified applicants. A qualified applicant is an applicant that has submitted a complete application and has met the selection criteria. Qualified applicants are eligible to be selected to participate in the shark research fishery for 2010. The HMS Management Division will provide the list of qualified applicants to the SEFSC. The SEFSC will then evaluate the list of qualified applicants and, based on the temporal and spatial needs of the research objectives, the availability of qualified applicants, and the available quota for a given year, will randomly select approximately 10 qualified applicants to conduct the prescribed research. Where there are multiple qualified applicants that meet the criteria, permittees will be randomly selected through a lottery system. If a public meeting is deemed necessary, NMFS will announce details of a public selection meeting in a subsequent **Federal Register** notice.

Once the selection process is complete, NMFS will notify the selected applicants and issue the shark research fishery permits. If needed, NMFS will communicate with the shark research fishery permit holders to arrange a captain's meeting to discuss the research objectives and protocols. The shark research fishery permit holders must contact the NMFS observer coordinator to arrange the placement of a NMFS-approved observer for each shark research trip.

A shark research fishery permit will only be valid for the vessel and owner(s) and terms and conditions listed on the permit, and thus, cannot be transferred to another vessel or owner(s). Issuance of a shark research permit does not guarantee that the permit holder will be assigned a NMFS-approved observer on any particular trip. Rather, issuance indicates that a vessel may be issued a NMFS-approved observer for a particular trip, and on such trips, may be allowed to harvest Atlantic sharks, including sandbar sharks, in excess of the retention limits described in 50 CFR 635.24(a). These retention limits will be based on available quota, number of vessels participating in the 2010 shark research fishery, the research objectives set forth by the shark board, and may vary by vessel and/or location. When not operating under the auspices of the shark research fishery, the vessel would still be able to land non-sandbar, SCS, and pelagic sharks subject to existing retention limits on trips without a NMFS-approved observer. The shark research permit may be revoked or modified at any time and does not confer the right to engage in activities beyond those listed on the shark research fishery permit.

Commercial shark permit holders (directed and incidental) are invited to submit an application to participate in the shark research fishery on an annual basis. Permit applications can be found on the HMS Management Division's website at: *http://www.nmfs.noaa.gov/sfa/hms/index.htm* or by calling (301) 713–2347. Final decisions on the issuance of a shark research fishery permit will depend on the submission of all required information, and NMFS' review of applicant information as outlined above. The 2010 shark research fishery will start after the opening of the shark fishery and under available quotas as published in a separate **Federal Register** final rule.

Dated: October 26, 2009.

Emily H. Menashes,

Deputy Director for Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. E9–26224 Filed 10–29–09; 8:45 am]

BILLING CODE 3510–22–S

DEPARTMENT OF COMMERCE

International Trade Administration

[A–475–820, A–588–843, A–580–829, A–469–807, A–583–828]

Stainless Steel Wire Rod From Italy, Japan, the Republic of Korea, Spain, and Taiwan: Final Results of the Expedited Sunset Reviews of the Antidumping Duty Orders

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

SUMMARY: On July 1, 2009, the Department of Commerce (the Department) initiated sunset reviews of the antidumping duty orders on stainless steel wire rod (SSWR) from Italy, Japan, the Republic of Korea (Korea), Spain, and Taiwan, pursuant to section 751(c) of the Tariff Act of 1930, as amended (the Act). The Department has conducted expedited (120-day) sunset reviews for these orders pursuant to 19 CFR 351.218(e)(1)(ii)(C)(2). As a result of these sunset reviews, the Department finds that revocation of the antidumping duty orders would be likely to lead to continuation or recurrence of dumping.

DATES: *Effective Date:* October 30, 2009.

FOR FURTHER INFORMATION CONTACT: Holly Phelps or Elizabeth Eastwood, AD/CVD Operations, Office 2, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street & Constitution Avenue, NW., Washington, DC 20230; *telephone:* (202) 482–0656 and (202) 482–3874, respectively.

SUPPLEMENTARY INFORMATION:

Background

On July 1, 2009, the Department published the notice of initiation of the sunset reviews of the antidumping duty orders on SSWR from Italy, Japan, Korea, Spain, and Taiwan pursuant to section 751(c) of the Act. *See Initiation of Five-Year (''Sunset'') Reviews,* 74 FR 31412 (July 1, 2009) (*Notice of Initiation*).

The Department received a notice of intent to participate from Carpenter Technology Corporation, a domestic interested party, within the deadline specified in 19 CFR 351.218(d)(1)(i). The company claimed interested party status under section 771(9)(C) of the Act as a manufacturer of a domestic like product in the United States.

The Department received a complete substantive response to the notice of initiation from the domestic interested party within the 30-day deadline specified in 19 CFR 351.218(d)(3)(i). We received no substantive responses from respondent interested parties with respect to any of the orders covered by these sunset reviews, nor was a hearing requested. As a result, pursuant to 19 CFR 351.218(e)(1)(ii)(C)(2), the Department conducted expedited (120-day) sunset reviews of the antidumping duty orders on SSWR from Italy, Japan, Korea, Spain, and Taiwan.

Scope of the Orders

The merchandise covered by these orders is SSWR, which comprises products that are hot-rolled or hot-rolled annealed and/or pickled and/or descaled rounds, squares, octagons, hexagons or other shapes, in coils, that may also be coated with a lubricant containing copper, lime, or oxalate. SSWR is made of alloy steels containing, by weight, 1.2 percent or less of carbon and 10.5 percent or more of chromium, with or without other elements. These products are manufactured only by hot-rolling or hot-rolling, annealing, and/or pickling and/or descaling, are normally sold in coiled form, and are of solid cross-section. The majority of SSWR sold in the United States is round in cross-sectional shape, annealed and pickled, and later cold-finished into stainless steel wire or small-diameter bar.

The most common size for such products is 5.5 millimeters or 0.217 inches in diameter, which represents the smallest size that normally is produced on a rolling mill and is the size that most wire-drawing machines are set up to draw. The range of SSWR sizes normally sold in the United States is between 0.20 inches and 1.312 inches diameter. Two stainless steel grades, SF20T and K–M35FL, are excluded from the scope of the order. The chemical makeup for the excluded grades is as follows:

SF20T:

Carbon	0.05 max
Chromium	19.00/21.00
Manganese	2.00 max
Molybdenum	1.50/2.50
Phosphorous	0.05 max
Lead	added (0.10/0.30)
Sulfur	0.15 max
Tellurium	added (0.03 min)
Silicon	1.00 max.

K–M35FL:

Carbon	0.015 max
Nickel	0.30 max
Silicon	0.70/1.00
Chromium	12.50/14.00
Manganese	0.40 max
Lead	0.10/0.30
Phosphorous	0.04 max
Aluminum	0.20/0.35
Sulfur	0.03 max.

The products subject to these orders are currently classifiable under subheadings 7221.00.0005, 7221.00.0015, 7221.00.0030, 7221.00.0045, and 7221.00.0075 of the Harmonized Tariff Schedule of the United States (HTSUS). Although the HTSUS subheadings are provided for convenience and customs purposes, the written description of the scope of these orders is dispositive.

Analysis of Comments Received

All issues raised in these reviews are addressed in the ''Issues and Decision Memorandum for the Expedited Sunset Reviews of the Antidumping Duty Orders on Stainless Steel Wire Rod from Italy, Japan, the Republic of Korea, Spain, and Taiwan'' from John M. Andersen, Acting Deputy Assistant Secretary for Antidumping and Countervailing Duty Operations, to Ronald K. Lorentzen, Acting Assistant Secretary for Import Administration (Oct. 29, 2009) (Decision Memo), which is hereby adopted by this notice. The issues discussed in the Decision Memo include the likelihood of continuation or recurrence of dumping and the magnitude of the margins likely to prevail if the orders were revoked. Parties can find a complete discussion of all issues raised in these reviews and the corresponding recommendations in this public memorandum which is on file in the Central Records Unit, room 1117 of the main Department building.

In addition, a complete version of the Decision Memo can be accessed directly on the Web at *http://ia.ita.doc.gov/frn.* The paper copy and electronic version of the Decision Memo are identical in content.

Final Results of Reviews

We determine that revocation of the antidumping duty orders on SSWR from Italy, Japan, Korea, Spain, and Taiwan would be likely to lead to continuation or recurrence of dumping at the following weighted-average percentage margins:

Manufacturers/exporters/producers	Weighted-average margin (percent)
Italy:	
Cogne Acciai Speciali S.r.l.	11.25
All-Others Rate	11.25
Japan:	
Daido Steel Co., Ltd.	34.21
Nippon Steel Corp.	21.18
Sanyo Special Steel Co., Ltd.	34.21
Sumitomo Electric Industries, Ltd.	34.21
All-Others Rate	25.26
Korea:	
Dongbang Special Steel Co., Ltd./Changwon Specialty Steel Co., Ltd./Pohang Iron and Steel Co., Ltd.	5.77
Sammi Steel Co., Ltd.	28.44
All-Others Rate	5.77
Spain:	
Roldan S.A.	2.71
All-Others Rate	2.71
Taiwan:	
Walsin Cartech Specialty Steel Corp.	8.29
All-Others Rate	8.29

This notice also serves as the only reminder to parties subject to administrative protective orders (APO) of their responsibility concerning the return or destruction of proprietary information disclosed under APO in accordance with 19 CFR 351.305. Timely notification of the return or destruction of APO materials or conversion to judicial protective orders is hereby requested. Failure to comply with the regulations and terms of an APO is a violation which is subject to sanction.

We are issuing and publishing the results and notice in accordance with sections 751(c), 752(c), and 777(i)(1) of the Act.

Dated: October 26, 2009.

John M. Andersen,

Acting Deputy Assistant Secretary for Antidumping and Countervailing Duty Operations.

[FR Doc. E9–26227 Filed 10–29–09; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–570–848]

Freshwater Crawfish Tail Meat From the People's Republic of China: Notice of Initiation of Antidumping Duty New-Shipper Review

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

DATES: *Effective Date:* October 30, 2009.

SUMMARY: On September 15, 2009, the Department of Commerce (the

Department) received a request to conduct a new-shipper review of the antidumping duty order on freshwater crawfish tail meat from the People's Republic of China (PRC). In accordance with section 751(a)(2)(B) of the Tariff Act of 1930, as amended (the Act), and 19 CFR 351.214(d), we are initiating an antidumping duty new-shipper review.

FOR FURTHER INFORMATION CONTACT: Hermes Pinilla or Minoo Hatten at (202) 482–3477 and (202) 482–1690, respectively, Office 5, AD/CVD Operations, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue, NW., Washington, DC 20230.

SUPPLEMENTARY INFORMATION:

Background

The Department published the antidumping duty order on freshwater crawfish tail meat from the PRC in the **Federal Register** on September 15, 1997. *See Notice of Amendment to Final Determination of Sales at Less than Fair Value and Antidumping Duty Order: Freshwater Crawfish Tail Meat from the People's Republic of China,* 62 FR 48218 (September 15, 1997). On September 15, 2009, we received a timely request for a new-shipper review of the antidumping duty order on freshwater crawfish tail meat from the PRC from Nanjing Gemsen International Co., Ltd. (Nanjing Gemsen). At our request, on October 13, 2009, Nanjing Gemsen submitted additional information to supplement its request for a new-shipper review. *See* memorandum to file dated October 13, 2009. Nanjing Gemsen certified that it is the exporter of the subject merchandise upon which the request for a new-shipper review is based.

Pursuant to section 751(a)(2)(B)(i)(I) of the Act and 19 CFR 351.214(b)(2)(ii)(A), Nanjing Gemsen certified that it did not export freshwater crawfish tail meat to the United States during the period of investigation (POI). Further, pursuant to 19 CFR 351.214(b)(2)(ii)(B), the producer, Henan Baoshu Aquatic Products Co., Ltd. (Henan Baoshu), certified that it did not export subject merchandise to the United States during the POI. In addition, pursuant to section 751(a)(2)(B)(i)(II) of the Act and 19 CFR 351.214(b)(2)(iii)(A), Nanjing Gemsen certified that, since the initiation of the investigation, it has never been affiliated with any PRC exporter or producer who exported freshwater crawfish tail meat to the United States during the POI, including those not individually examined during the investigation. As required by 19 CFR 351.214(b)(2)(iii)(B), Nanjing Gemsen also certified that its export activities are not controlled by the central government of the PRC.

In addition to the certifications described above, pursuant to 19 CFR 351.214(b)(2)(iv), Nanjing Gemsen submitted documentation establishing the date on which it first shipped freshwater crawfish tail meat for export to the United States and the date on which the freshwater crawfish tail meat was first entered, or withdrawn from warehouse, for consumption, the volume of its first shipment, and the date of its first sale to an unaffiliated customer in the United States.

The Department conducted a query of the U.S. Customs and Border Protection (CBP) database to confirm that Nanjing Gemsen's shipment of subject merchandise had entered the United States for consumption and had been suspended for antidumping duties. The Department also corroborated Nanjing Gemsen's assertion that it made subsequent shipments to the United States by reviewing CBP data.

We did not receive comments from Crawfish Processors Alliance (the petitioner) on Nanjing Gemsen's request for a new-shipper review.

Initiation of New-Shipper Review

Pursuant to section 751(a)(2)(B) of the Act and 19 CFR 351.214(d)(1), the Department finds that Nanjing Gemsen's request meets the threshold requirements for initiation of a new-shipper review for the shipment of freshwater crawfish tail meat from the PRC. *See* Memorandum to the File entitled: ''New-Shipper Review Initiation Checklist'' dated October 26, 2009.

The period of review for this new-shipper review is September 1, 2008, through August 31, 2009. *See* 19 CFR 351.214(g)(1)(i)(A). The Department intends to issue the preliminary results of this review no later than 180 days from the date of initiation and final results of this review no later than 270 days from the date of initiation. *See* section 751(a)(2)(B)(iv) of the Act.

Interested parties requiring access to proprietary information in this new-shipper review should submit applications for disclosure under administrative protective order in accordance with 19 CFR 351.305 and 351.306.

Because Nanjing Gemsen certified that it exported subject merchandise produced by Henan Baoshu, the sales of which form the basis for the request for a new-shipper review, we will instruct CBP to allow, at the option of the importer until the completion of the review, the posting of a bond or security in lieu of a cash deposit for each entry of the subject merchandise produced by Henan Baoshu and exported by Nanjing Gemsen in accordance with section 751(a)(2)(B)(iii) of the Act and 19 CFR 351.214(e). The bonding privilege will apply only to subject merchandise produced by Henan Baoshu and exported by Nanjing Gemsen.

This initiation and notice are published in accordance with section 751(a)(2)(B) of the Act and 19 CFR 351.214 and 351.221(c)(1)(i).

Dated: October 26, 2009.

John M. Andersen,

Acting Deputy Assistant Secretary for Antidumping and Countervailing Duty Operations.

[FR Doc. E9–26228 Filed 10–29–09; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XS65

New England Fishery Management Council; Public Meeting

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

ACTION: Notice of a public meeting.

SUMMARY: The New England Fishery Management Council (Council) will hold a 3-day Council meeting on November 17–19, 2009, to consider actions affecting New England fisheries in the exclusive economic zone (EEZ).

DATES: The meeting will begin on Tuesday, November 17 at 8:30 a.m. and Wednesday and Thursday, November 18 and 19, beginning at 8 a.m.

ADDRESSES: The meeting will be held at the Hyatt Regency Newport, 1 Goat Island, Newport, RI 02840; telephone: (401) 851–1234; fax: (401) 846–7210.

Council address: New England Fishery Management Council, 50 Water Street, Mill 2, Newburyport, MA 01950.

FOR FURTHER INFORMATION CONTACT: Paul J. Howard, Executive Director, New England Fishery Management Council; telephone: (978) 465–0492.

SUPPLEMENTARY INFORMATION:

Tuesday, November 17, 2009

Following introductions and any announcements, the Council will discuss and approve its management priorities for 2010. The Scientific and Statistical Committee (SSC) Chairman will then present the results of the committee(s recent deliberations concerning Atlantic herring. At the request of the Council, the SSC was asked to revisit the size of the 40% buffer between the herring Overfishing Level and Acceptable Biological Catch to consider whether application of recent years retrospective difference of about 17% is sufficient to account for scientific uncertainty caused by retrospective patterns. Prior to a lunch break the Herring Committee will ask the Council to approve final recommendations for multi-year herring fishery specifications (2010–12). The specifications will address overfishing levels, acceptable biological catch, management uncertainty and, among other issues, the Total Allowable Catch and Annual Catch Limits for each of the four herring management areas. The Council also will receive an update on the development of catch monitoring alternatives to be included in Amendment 5 to the Atlantic Herring Fishery Management Plan (FMP) and based on the discussion, may restructure the alternatives. This and the previous herring agenda item will be discussed until the meeting adjourns at the end of the afternoon.

Wednesday, November 18, 2009

The second day of the Council meeting will begin with a review and approval of final measures for inclusion in Framework 21 to the Atlantic Sea Scallop FMP. Measures under consideration for implementation in the 2010 fishing year will address compliance with a reasonable and prudent alternative provided in the most recent NMFS Biological Opinion for the FMP regarding sea turtle interactions, fishery specifications for both limited access and general category fleets, area rotation adjustments, and other measures. The Council also will review preliminary analyses concerning the potential impacts of various yellowtail flounder allocation alternatives on the scallop fishery. The allocation is being considered in a specifications package for the groundfish fishery for fishing years 2010–12.

The Groundfish Committee will ask the Council to approve Framework Adjustment 44 to the Northeast Multispecies FMP. The action is intended to include the specification of annual catch limits for fishing years 2010–12,and the yellowtail flounder sub-components for the scallop fishery. The Council also will address modifications to the groundfish common pool effort control measures such as trip limits or differential days-at-sea counting in order to meet the Council's fishing mortality targets for several groundfish stocks.

Thursday, November 19, 2009

The Council will begin the last day of the meeting with a series of brief reports from the Council Chairman and Executive Director, the NOAA Fisheries Northeast Regional Administrator, Northeast Fisheries Science Center and Mid-Atlantic Fishery Management Council liaisons, NOAA General Counsel, representatives of the U.S. Coast Guard and the Atlantic States Marine Fisheries Commission, as well as NOAA Enforcement. These reports will be followed by a review of any experimental fishery permit applications that have been received since the last Council meeting. The Council will also approve final recommendations for 2010 specifications for the red crab fishery. The discussion will include a review of the Red Crab Plan Development Team's analyses; the specifications will address acceptable biological catch based on the recommendation of the Council's SSC. Following a lunch break, the Council will accept public comments on issues related to fisheries management issues, but not listed on the meeting agenda. During the afternoon session, the Council plans to approve draft measures to be included in Amendment 5 to the Monkfish FMP. Issues to be considered will include annual catch limits, accountability measures, trip limits and days-at-sea for 2011–13. Following Council approval, the amendment and accompanying documents will be made available for public review and comment. The day will conclude with a review and possible development of Council positions on bluefin tuna and swordfishh management. Before adjournment, the Council may address any other outstanding business related to this meeting.

Although other non-emergency issues not contained in this agenda may come before this Council for discussion, those issues may not be the subjects of formal action during this meeting. Council action will be restricted to those issues specifically listed in this notice and any issues arising after publication of this notice that require emergency action under section 305(c) of the Magnuson-Stevens Act, provided that the public has been notified of the Council's intent to take final action to address the emergency.

Special Accommodations

This meeting is physically accessible to people with disabilities. Requests for sign language interpretation or other auxiliary aids should be directed to Paul J. Howard (see **ADDRESSES**) at least 5 days prior to the meeting date.

Dated: October 27, 2009.

Tracey L. Thompson,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. E9–26189 Filed 10–29–09; 8:45 am]

BILLING CODE 3510–22–S

COMMODITY FUTURES TRADING COMMISSION

Meetings; Sunshine Act

AGENCY HOLDING THE MEETING: Commodity Futures Trading Commission.

Sunshine Act Meetings

TIME AND DATE: 11 a.m., Friday, November 6, 2009.

PLACE: 1155 21st St., NW., Washington, DC, 9th Floor Commission Conference Room.

STATUS: Closed.

MATTERS TO BE CONSIDERED: Surveillance Matters.

CONTACT PERSON FOR MORE INFORMATION: Sauntia S. Warfield, 202–418–5084.

Sauntia S. Warfield,

Assistant Secretary of the Commission.

[FR Doc. E9–26326 Filed 10–28–09; 4:15 pm]

BILLING CODE 6351–01–P

COMMODITY FUTURES TRADING COMMISSION

Sunshine Act Meetings

AGENCY HOLDING THE MEETING: Commodity Futures Trading Commission.

TIME AND DATE: 11 a.m., Friday, November 27, 2009.

PLACE: 1155 21st St., NW., Washington, DC, 9th Floor Commission Conference Room.

STATUS: Closed.

MATTERS TO BE CONSIDERED: Surveillance matters.

CONTACT PERSON FOR MORE INFORMATION: Sauntia S. Warfield, 202–418–5084.

Sauntia S. Warfield,

Assistant Secretary of the Commission.

[FR Doc. E9–26329 Filed 10–28–09; 4:15 pm]

BILLING CODE 6351–01–P

COMMODITY FUTURES TRADING COMMISSION

Meetings; Sunshine Act

AGENCY HOLDING THE MEETING: Commodity Futures Trading Commission.

Sunshine Act Meetings

TIME AND DATE: 11 a.m., November 20, 2009.

PLACE: 1155 21st St., NW., Washington, DC, 9th Floor Commission Conference Room.

STATUS: Closed.

MATTERS TO BE CONSIDERED: Surveillance Matters.

CONTACT PERSON FOR MORE INFORMATION: Sauntia S. Warfield, 202–418–5084.

Sauntia S. Warfield,

Assistant Secretary of the Commission.

[FR Doc. E9–26330 Filed 10–28–09; 4:15 pm]

BILLING CODE 6351–01–P

COMMODITY FUTURES TRADING COMMISSION

Sunshine Act Meeting Notice

TIME AND DATE: 2 p.m., Wednesday November 18, 2009.

PLACE: 1155 21st St., NW., Washington, DC, 9th Floor Commission Conference Room.

STATUS: Closed.

MATTERS TO BE CONSIDERED: Enforcement Matters.

CONTACT PERSON FOR MORE INFORMATION: Sauntia S. Warfield, 202–418–5084.

Sauntia S. Warfield,

Assistant Secretary of the Commission.

[FR Doc. E9–26333 Filed 10–28–09; 4:15 pm]

BILLING CODE 6351–01–P

COMMODITY FUTURES TRADING COMMISSION

Sunshine Act Meeting Notice

TIME AND DATE: 11 a.m., Friday, November 13, 2009.

PLACE: 1155 21st St., NW., Washington, DC, 9th Floor Commission Conference Room.

STATUS: Closed.

MATTERS TO BE CONSIDERED: Surveillance Matters.

CONTACT PERSON FOR MORE INFORMATION: Sauntia S. Warfield, 202–418–5084.

Sauntia S. Warfield,

Assistant Secretary of the Commission.

[FR Doc. E9–26331 Filed 10–28–09; 4:15 pm]

BILLING CODE 6351–01–P

CONSUMER PRODUCT SAFETY COMMISSION

Sunshine Act Meetings

TIME AND DATE: Wednesday, November 4, 2009, 9 a.m.–12 noon.

PLACE: Hearing Room 420, Bethesda Towers, 4330 East-West Highway, Bethesda, Maryland.

STATUS: Commission Meeting—Open to the Public.

MATTERS TO BE CONSIDERED: Pending Decisional Matter: Brass Lead Exclusion Petition.

(Immediately following the decision, the Public Hearing on Unblockable Drains will begin.)

A live webcast of the Meeting can be viewed at *http://www.cpsc.gov/webcast/index.html.*

For a recorded message containing the latest agenda information, call (301) 504–7948.

CONTACT PERSON FOR MORE INFORMATION: Todd A. Stevenson, Office of the Secretary, U.S. Consumer Product Safety Commission, 4330 East West Highway, Bethesda, MD 20814, (301) 504–7923.

Dated: October 23, 2009.

Todd A. Stevenson,

Secretary.

[FR Doc. E9–26067 Filed 10–29–09; 8:45 am]

BILLING CODE 6355–01–M

CONSUMER PRODUCT SAFETY COMMISSION

Sunshine Act Meetings

TIME AND DATE: Wednesday, November 4, 2009, 2 p.m.

PLACE: Hearing Room 420, Bethesda Towers, 4330 East-West Highway, Bethesda, Maryland.

STATUS: Closed to the public.

MATTER TO BE CONSIDERED:

Compliance Weekly Report—Commission Briefing

The staff will brief the Commission on various compliance matters.

For a recorded message containing the latest agenda information, call (301) 504–7948.

CONTACT PERSON FOR MORE INFORMATION: Todd A. Stevenson, Office of the Secretary, U.S. Consumer Product Safety Commission, 4330 East-West Highway, Bethesda, MD 20814, (301) 504–7923.

Dated: October 23, 2009.

Todd A. Stevenson,

Secretary.

[FR Doc. E9–26083 Filed 10–29–09; 8:45 am]

BILLING CODE 6355–01–M

CORPORATION FOR NATIONAL AND COMMUNITY SERVICE

Information Collection; Submission for OMB Review, Comment Request

AGENCY: Corporation for National and Community Service.

ACTION: Notice.

SUMMARY: The Corporation for National and Community Service (hereinafter the ''Corporation''), has submitted a public information collection request (ICR) entitled the ''Day of Service Registration and Reporting'' to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995, Public Law 104–13, (44 U.S.C. Chapter 35). Copies of this ICR, with applicable supporting documentation, may be obtained by calling the Corporation for National and Community Service, Mr. David Premo at (202) 606–6717. Individuals who use a telecommunications device for the deaf (TTY–TDD) may call (202) 565–2799 between 8:30 a.m. and 5 p.m. eastern time, Monday through Friday.

ADDRESSES: Comments may be submitted, identified by the title of the information collection activity, to the Office of Information and Regulatory Affairs, Attn: Ms. Sharon Mar, OMB Desk Officer for the Corporation for National and Community Service, by any of the following two methods within 30 days from the date of publication in this **Federal Register**:

(1) *By fax to:* (202) 395–6974, Attention: Ms. Sharon Mar, OMB Desk Officer for the Corporation for National and Community Service; and

(2) *Electronically by e-mail to: smar@omb.eop.gov.*

SUPPLEMENTARY INFORMATION: The OMB is particularly interested in comments which:

- Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Corporation, including whether the information will have practical utility;
- Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

• Propose ways to enhance the quality, utility, and clarity of the information to be collected; and

• Propose ways to minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submissions of responses.

Comments

A 60-day public comment Notice was published in the **Federal Register** on July 31, 2009. This comment period ended September 29, 2009. No public comments were received from this notice.

Description: The Corporation seeks to renew the Day of Service Registration and Reporting (Serve.gov). The purpose of this information collection is to help expand volunteering throughout the country. No comments from the public were received in the 60-day comment period. Revisions in the original collection are being made based on recent feedback and input received from the Board of Directors and the external partners. CNCS will no longer be collecting information for the purpose of posting volunteering opportunities for the general public. Numerous organizations provide this service for free. Much of the information we have been collecting is no longer useful.

We will continue to use this information collection for reporting purposes. CNCS stakeholders such as grantees will use it to share activities, promote service and volunteering, and highlight best practices and innovation. We will use this information measure success, for media purposes, for congressional response, and other critical tasks. The submitted collection reflects the minimum information we need to perform these tasks.

Type of Review: Renewal, previously granted emergency clearance.

Agency: Corporation for National and Community Service.

Title: ''Day of Service Registration and Reporting (Serve.gov)''.

OMB Number: 3045–0122.

Agency Number: None.

Affected Public: Nonprofit organizations.

Total Respondents: 50,000 respondents for reporting accomplishments.

Frequency: Annual.

Average Time per Response: 20 minutes.

Estimated Total Burden Hours: 16,667 hours.

Total Burden Cost (capital/startup): None.

Total Burden Cost (operating/maintenance): None.

Dated: October 23, 2009.

Rhonda Taylor,

Acting Director, Office of Corporate Relations.

[FR Doc. E9–26139 Filed 10–29–09; 8:45 am]

BILLING CODE 6050–$$–P

DEPARTMENT OF DEFENSE

Office of the Secretary

[Docket ID DOD–2009–HA–0155]

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: 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; the accuracy of the agency's estimate of the burden of the proposed information collection; ways to enhance the quality, utility, and clarity of the information to be collected; and 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 December 29, 2009.

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, 1160 Defense Pentagon, Washington, DC 20301–1160.

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 the Office of the Assistant Secretary of Defense (Health Affairs), Force Health Protection and Readiness, Psychological Health Strategic Operations, *Attn:* Dr. Jill Carty, Falls Church, VA 22041–3258, or call Dr. Jill Carty at (703) 845–3317.

Title; Associated Form; and MB Number: Retention of Behavioral Health Providers Survey and Focus Groups; OMB Control Number 0720–TBD.

Needs and Uses: The Force Health Protection and Readiness (FHP&R) program has hired Lockheed Martin to develop and implement a survey instrument to evaluate retention of behavioral health providers (psychiatrists and psychologists). Lockheed Martin is working with a subcontractor, Mathematica Policy Research, whose staff will help with the survey data collection for this project.

Affected Public: Former psychiatrists and psychologists who served in the military.

Annual Burden Hours: 200.

Number of Respondents: 800.

Responses per Respondent: 1.

Average Burden per Response: 15 minutes.

Frequency: One time.

SUPPLEMENTARY INFORMATION:

Summary of Information Collection

The survey will targeted to current psychiatrists and psychologists from the Army, Navy, and Air Force, as well as former Army, Navy, and Air Force psychiatrists and psychologists who left the military in fiscal year 2006, 2007, or 2008 for reasons other than retirement. Participation is voluntary and confidential. All identifying information will be removed before results are sent to the Department of Defense. Only group statistics will be compiled and shared. No individual information will be disclosed.

Information collected will include type of behavioral health provider, importance of different factors influencing decision to join the military, deployment information, ratings of military mental health treatment, salary information, satisfaction with being a military mental health provider, overall health status, and demographic information. Former providers also will be surveyed about reasons for leaving the military, current work status, satisfaction with current employment and salary information, potential influences that could have extended military service. Current providers also will be surveyed about reasons that might influence decision to extend military service, first and last name, rank, type of behavioral health provider, date left service (if former provider), mailing address, e-mail address, phone number (home and cell), and installation/last installation.

The survey will be distributed for completion on the Web via e-mail. For individuals where a valid e-mail address cannot be found, a paper copy of the survey with a prepaid return envelope will be mailed.

The methodology, results, and recommendations will be summarized via a report for TMA. Policy recommendations will include suggestions of methods to incentivize service members to remain in service.

Dated: October 23, 2009.

Patricia L. Toppings,

OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. E9–26184 Filed 10–29–09; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Office of the Secretary

Availability of the Fiscal Year 2008 Defense Advanced Research Projects Agency (DARPA) Services Contracts Inventory

AGENCY: Defense Advanced Research Projects Agency (DARPA), DoD.

ACTION: Notice of availability.

SUMMARY: In accordance with section 2330a of Title 10 United States Code as amended by the National Defense Authorization Act for Fiscal Year 2008 (NDAA 08) Section 807, the Director of the Defense Advanced Research Projects Agency and the Office of the Director, Defense Procurement and Acquisition Policy, Office of Strategic Sourcing (DPAP/SS) will make available to the public the first inventory of activities performed pursuant to contracts for services. The inventory will be published to the Defense Advanced Research Projects Agency (DARPA) Web site at the following location: *http://www.darpa.mil/cmo/section807.html.*

DATES: Inventory to be made publically available within 30 days after publication of this notice.

ADDRESSES: Send written comments and suggestions concerning this inventory to Kristen Fuller, Special Assistant to the Deputy Director of the Contracts Management Office, 3701 N Fairfax Drive, Arlington VA 22203.

FOR FURTHER INFORMATION CONTACT: Kristen Fuller at (703) 526–4168 or e-mail *Kristen.Fuller@darpa.mil.*

Dated: October 26, 2009.

Patricia L. Toppings,

OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. E9–26185 Filed 10–29–09; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Office of the Secretary

Availability of the Fiscal Year 2008 TRICARE Management Activity (TMA) Services Contract Inventory

AGENCY: TRICARE Management Activity, Office of the Secretary of Defense, DoD.

ACTION: Notice of availability.

SUMMARY: In accordance with section 2330a of Title 10 United States Code as amended by the National Defense Authorization Act for Fiscal Year 2008 (NDAA 08) section 807, the Acting Chief Functional Officer for Acquisition Management and Support Directorate (AM&S), TRICARE Management Activity, in coordination with the Office of the Director, Defense Procurement and Acquisition Policy, Office of Strategic Sourcing (DPAP/SS) will make available to the public the first inventory of activities performed pursuant to contracts for services. The inventory will be published to the TMA Web site at the following location: *http://www.tricare.mil/contracting/healthcare/default.aspx.*

DATES: Inventory to be made publicly available not later than 30 days after the date on which the inventory was submitted to Congress. The TMA inventory was transmitted to Congress on September 29, 2009.

ADDRESSES: Send written comments or suggestions concerning the inventory to Bruce Mitterer, Acquisition Policy and Pricing Division, TRICARE Management Activity, 16401 East Centretech Parkway, Aurora, CO 80011.

FOR FURTHER INFORMATION CONTACT: Bruce Mitterer, (303) 676–3812 or e-mail at *Bruce.Mitterer@tma.osd.mil.*

SUPPLEMENTARY INFORMATION: NDAA 08, section 807 amends section 2330a of Title 10 United States Code to require annual inventories and reviews of activities performed on services contracts. TMA AM&S submitted the TMA Fiscal Year 2008 Services Contract Inventory to the Office of the DPAP/SS on August 28, 2009. Included with this inventory was a narrative that describes the methodology used to populate the Inventory data fields. The TMA inventory was transmitted to Congress on September 29, 2009. The posted inventory does not include the contract number, contractor identification, or other identifying information as this data could be used to disclose what may be considered contractor proprietary information.

Dated: October 26, 2009.

Patricia L. Toppings,

OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. E9–26186 Filed 10–29–09; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Department of the Army

Notice of Availability of a Draft Environmental Impact Statement (DEIS) for Training Land Acquisition at Fort Polk, LA

AGENCY: Department of the Army, DoD.

ACTION: Notice of Availability (NOA).

SUMMARY: The Department of the Army has prepared a DEIS that analyzes environmental and socioeconomic impacts connected with the proposed acquisition (hereinafter to mean including purchase and lease) and use of up to 100,000 additional acres of commercial and private lands for training in the vicinity of Fort Polk, Louisiana. This Proposed Action to acquire additional lands supports the training requirements of the Joint Readiness Training Center (JRTC) and Fort Polk's current and future resident units. The DEIS analyzes three alternatives that are deemed feasible and meet the purpose and need for this Proposed Action.

DATES: The public comment period for the DEIS will end 45 days after the publication of the NOA in the **Federal Register** by the U.S. Environmental Protection Agency.

ADDRESSES: To request a copy of the DEIS contact Ms. Susan Walker, Fort Polk Public Affairs Office, 7073 Radio Road, Fort Polk, LA 71459–5342. Comments may also be e-mailed to *Susan.T.Walker@conus.army.mil.*

FOR FURTHER INFORMATION CONTACT: Ms. Susan Walker at (337) 531–9125 during normal business hours from 9 a.m. to 5 p.m. CST.

SUPPLEMENTARY INFORMATION: Fort Polk, located in west-central Louisiana, is one of the Army's premier power projection platforms and also the home of the JRTC. Fort Polk is currently comprised of approximately 198,130 acres of U.S. Army-owned land and lands utilized under a special use permit with the U.S. Forest Service. In order to improve the training requirements of Fort Polk's units and the JRTC, the Army has proposed to acquire up to 100,000 acres of additional land to enhance realistic training conditions. Additional training lands will allow Soldiers of the JRTC to train on brigade-level combat maneuver training tasks while simultaneously allowing Fort Polk's resident units to conduct maneuver and live-fire training. This additional land will enhance training for Fort Polk units and units deploying to JRTC, will reduce the need for training work arounds, and will allow Soldiers to train to more realistic standards in preparation for operational deployment.

The Fort, Polk DEIS analyzes the environmental and socioeconomic impacts of several acquisition location alternatives, each of which could include the acquisition of up to 100,000 acres of land. Alternative 1 considers the acquisition of lands directly adjacent to Fort Polk's existing training areas to the south of Peason Ridge and directly north and east of the main post. As part of Alternative 1, units would continue to lease lands to convoy to Peason Ridge to access training areas. Alternative 2 considers the acquisition of the land considered in Alternative 1 and, in addition, considers the acquisition of parcels that connect Peason Ridge with Fort Polk's main post. Alternative 3 considers the acquisition of those lands considered in Alternative 2 and, in addition, considers the acquisition of lands to the east of Fort Polk in Rapides Parish. The DEIS also analyzes the No Action Alternative, which evaluates the impacts of taking no action to acquire or use additional training land around Fort Polk.

The Army has determined that significant impacts may possibly occur in regard to land use and noise for each of the three alternatives being considered. The Army projects that moderate impacts would occur to soil resources, water resources, wetlands, biological resources, cultural resources, and socioeconomics as a result of implementing the Proposed Action. The DEIS serves as documentation of the installation's compliance with Section 106 of the National Historic Preservation Act in accordance with 36 CFR 800.3–800.6. Substantive compliance with these provisions of the Advisory Council on Historic Preservation's regulations will be achieved through NEPA.

The public and any consulting parties are invited to review and comment on the DEIS. Public meetings will be announced in local media sources.

Comments from the public and consultation with consulting parties will be considered before any decision is made regarding implementing the Proposed Action at Fort Polk.

Dated: October 23, 2009.

Addison D. Davis IV,

Deputy Assistant Secretary of the Army (Environment, Safety and Occupational Health).

[FR Doc. E9–26088 Filed 10–29–09; 8:45 am]

BILLING CODE 3710–08–M

DEPARTMENT OF DEFENSE

Department of the Army; Corps of Engineers

Availability of the Draft Environmental Impact Statement for the Moffat Collection System Project, City and County of Denver, Adams County, Boulder County, Jefferson County, and Grand County, CO

AGENCY: Department of the Army, U.S. Army Corps of Engineers, DoD.

ACTION: Notice of availability.

SUMMARY: The U.S. Army Corps of Engineers (Corps) Omaha District has prepared a Draft Environmental Impact Statement (EIS) to analyze the direct, indirect, and cumulative effects of a water supply project called the Moffat Collection System Project (Moffat Project) in the City and County of Denver, Adams County, Boulder County, Jefferson County, and Grand County, CO. The purpose of the Proposed Action is to develop 18,000 acre-feet (AF) per year of new, firm yield to the Moffat Water Treatment Plant (WTP) and raw water customers upstream of the Moffat WTP pursuant to the Board of Water Commissioners' commitment to its customers. Denver Water's need for the proposed Moffat Project is to address two major issues: (1) Timeliness: the overall near-term water supply shortage, and (2) location: the imbalance in water storage and supply between the North and South systems. The Moffat Project would result in direct impacts to jurisdictional waters of the United States (U.S.), including wetlands. The placement of fill material in these waters of the U.S. for the construction of water storage and distribution facilities associated with developing additional water supplies requires authorization from the Corps under Section 404 of the Clean Water Act. The Permittee and Applicant is the City and County of Denver, acting by and through its Board of Water Commissioners (Denver Water).

The Draft EIS was prepared in accordance with the National Environmental Policy Act (NEPA) of 1969, as amended, and the Corps' regulations for NEPA implementation (33 Code of Federal Regulations [CFR] parts 230 and 325, Appendices B and C). The Corps Omaha District, Denver Regulatory Office is the lead federal agency responsible for the Draft EIS and information contained in the EIS serves as the basis for a decision regarding issuance of a Section 404 Permit. It also provides information for local and state agencies having jurisdictional responsibility for affected resources.

DATES: Written comments on the Draft EIS will be accepted on or before January 28, 2010. Public open houses and hearings will be held on December 1, 2, and 3, 2009.

ADDRESSES: Send written comments regarding the Proposed Action and Draft EIS to Scott Franklin, Moffat EIS Project Manager, U.S. Army Corps of Engineers, Omaha District—Denver Regulatory Office, 9307 South Wadsworth Boulevard, Littleton, CO 80128 or via *e-mail: moffat.eis@usace.army.mil.* Requests to be placed on or removed from the mailing list should also be sent to this address.

FOR FURTHER INFORMATION CONTACT: Scott Franklin, Moffat EIS Project Manager, U.S. Army Corps of Engineers at 303–979–4120; Fax 303–979–0602.

SUPPLEMENTARY INFORMATION: The purpose of the Draft EIS is to provide decision-makers and the public with information pertaining to the Proposed Action and alternatives, and to disclose environmental impacts and identify mitigation measures to reduce impacts. Denver Water proposes to enlarge its existing 41,811 AF Gross Reservoir by 72,000 AF to a total storage capacity of 113,811 AF. Gross Dam is located in Boulder County, CO, approximately 35 miles northwest of Denver and 6 miles southwest of the city of Boulder. The enlargement would be accomplished by raising the existing concrete gravity arch dam by 125 feet, from 340 to 465 feet high. The surface area of the reservoir would be expanded from approximately 418 acres to 818 acres. Using existing collection infrastructure, water from the Fraser River, Williams Fork River, and South Boulder Creek would be diverted and delivered during average to wet years via the Moffat Tunnel and South Boulder Creek to Gross Reservoir. There would be no additional diversions in dry years because Denver Water already diverts the maximum amount physically and legally available under their existing water rights. In order to firm this water supply and provide 18,000 AF per year of new firm yield, an additional 72,000 AF of storage capacity is necessary. To meet future demands, in most years, Denver Water would continue to rely on supplies from its entire integrated collection system. In a drought or emergency, Denver Water would rely on the additional water it would have previously stored in the Moffat Collection System to provide the additional 18,000 AF of yield.

In addition to the Proposed Action (Alternative 1a)—Gross Reservoir Expansion (Additional 72,000 AF), the Draft EIS analyzes five alternatives: (1) Alternative 1c—Gross Reservoir Expansion (Additional 40,700 AF)/New Leyden Gulch Reservoir (31,300 AF), (2) Alternative 8a—Gross Reservoir Expansion (Additional 52,000 AF)/ Reusable Return Flows/Gravel Pit Storage (5,000 AF), (3) Alternative 10a—Gross Reservoir Expansion (Additional 52,000 AF)/Reusable Return Flows/ Denver Basin Aquifer Storage (20,000 AF), (4) Alternative 13a—Gross Reservoir Expansion (Additional 60,000 AF)/Transfer of Agricultural Water Rights/Gravel Pit Storage (3,625 AF), and (5) No Action Alternative, which assumes that Denver Water would not receive approval from the Corps to implement the Moffat Project. Denver Water would rely upon a combination of strategies including using a portion of its Strategic Water Reserve and imposing mandatory restrictions to reduce demand during droughts.

Copies of the Draft EIS will be available for review at:

1. Arvada Library, 7525 W. 57th Avenue, Arvada, CO 80002.
2. Boulder County Main Library, 1001 Arapahoe Avenue, Boulder, CO 80302.
3. Denver Central Library, 10 W. 14th Avenue Parkway, Denver, CO 80204.
4. Fraser Valley Library, 421 Norgren Road, Fraser, CO 80442.
5. Golden Library, 1019 10th Street, Golden, CO 80401.
6. Granby Library, 55 Zero Street, Granby, CO 80446.
7. Kremmling Library, 300 S. 8th Street, Kremmling, CO 80459.
8. Summit County Library North Branch, 651 Center Circle, Silverthorne, CO 80498.
9. Summit County Library South Branch, 504 Airport Road, Breckenridge, CO 80424.
10. Thornton Branch Library, 8992 Washington Street, Thornton, CO 80229.
11. Denver Water, 1600 W. 12th Avenue, Denver, CO 80204.
12. U.S. Army Corps of Engineers, Denver Regulatory Office, 9307 S. Wadsworth Boulevard, Littleton, CO 80128.
13. Electronically at *https://www.nwo.usace.army.mil/html/od-tl/eis-info.htm.*

Oral and/or written comments may also be presented at Open Houses and Public Hearings to be held at 4 p.m. (Open House) and 6 p.m. (Public Hearing) on Tuesday, December 1, 2009 at the Boulder Country Club (7350 Clubhouse Road), Boulder, CO; at 4 p.m. (Open House) and 6 p.m. (Public Hearing) on Wednesday, December 2, 2009 at The Inn at SilverCreek—Grand Ballroom (62927 US Highway 40) Granby, CO; and at 4 p.m. (Open House) and 6 p.m. (Public Hearing) on Thursday, December 3, 2009 at the Doubletree Hotel—Grand Ballroom II (3203 Quebec Street), Denver, CO.

Timothy T. Carey,

Chief, Denver Regulatory Office.

[FR Doc. E9–26164 Filed 10–29–09; 8:45 am]

BILLING CODE 3720–58–P

DEPARTMENT OF EDUCATION

Submission for OMB Review; Comment Request

AGENCY: Department of Education.

SUMMARY: The Director, Information Collection Clearance Division, Regulatory Information Management Services, Office of Management invites comments on the submission for OMB review as required by the Paperwork Reduction Act of 1995.

DATES: Interested persons are invited to submit comments on or before November 30, 2009.

ADDRESSES: Written comments should be addressed to the Office of Information and Regulatory Affairs, Attention: Education Desk Officer, Office of Management and Budget, 725 17th Street, NW., Room 10222, New Executive Office Building, Washington, DC 20503, be faxed to (202) 395–5806 or send e-mail to *oira_submission@omb.eop.gov.*

SUPPLEMENTARY INFORMATION: Section 3506 of the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35) requires that the Office of Management and Budget (OMB) provide interested Federal agencies and the public an early opportunity to comment on information collection requests. OMB may amend or waive the requirement for public consultation to the extent that public participation in the approval process would defeat the purpose of the information collection, violate State or Federal law, or substantially interfere with any agency's ability to perform its statutory obligations. The IC Clearance Official, Regulatory Information Management Services, Office of Management, publishes that notice containing proposed information collection requests prior to submission of these requests to OMB. Each proposed information collection, grouped by office, contains the following: (1) Type of review requested, e.g. new, revision, extension, existing or reinstatement; (2) Title; (3) Summary of the collection; (4) Description of the need for, and proposed use of, the information; (5) Respondents and frequency of collection; and (6) Reporting and/or Recordkeeping burden. OMB invites public comment.

Dated: October 27, 2009.

Angela C. Arrington,

Director, Information Collection Clearance Division, Regulatory Information Management Services, Office of Management.

Federal Student Aid

Type of Review: New.

Title: Student Assistance General Provisions Annual Fire Safety Report.

Frequency: On Occasion.

Affected Public: Not-for-profit institutions; State, Local, or Tribal Gov't, SEAs or LEAs.

Reporting and Recordkeeping Hour Burden:

Responses: 7,282.

Burden Hours: 7,283.

Abstract: This new regulation requires the collection of statistics on fires in on-campus student housing facilities, the establishment of a fire log available for public inspection, and the publication of an annual fire safety report containing the institutional policies regarding fire safety and fire statistics.

Requests for copies of the information collection submission for OMB review may be accessed from *http://edicsweb.ed.gov,* by selecting the ''Browse Pending Collections'' link and by clicking on link number 4077. When you access the information collection, click on ''Download Attachments'' to view. Written requests for information should be addressed to U.S. Department of Education, 400 Maryland Avenue, SW., LBJ, Washington, DC 20202–4537. Requests may also be electronically mailed to the Internet address *ICDocketMgr@ed.gov* or faxed to 202–401–0920. Please specify the complete title of the information collection when making your request.

Comments regarding burden and/or the collection activity requirements should be electronically mailed to *ICDocketMgr@ed.gov.* Individuals who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339.

[FR Doc. E9–26231 Filed 10–29–09; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF EDUCATION

Submission for OMB Review; Comment Request

AGENCY: Department of Education.

SUMMARY: The Director, Information Collection Clearance Division, Regulatory Information Management Services, Office of Management invites comments on the submission for OMB review as required by the Paperwork Reduction Act of 1995.

DATES: Interested persons are invited to submit comments on or before November 30, 2009.

ADDRESSES: Written comments should be addressed to the Office of Information and Regulatory Affairs, *Attention:* Education Desk Officer, Office of Management and Budget, 725 17th Street, NW., Room 10222, New Executive Office Building, Washington, DC 20503, be faxed to (202) 395–5806 or send e-mail to *oira_submission@omb.eop.gov.*

SUPPLEMENTARY INFORMATION: Section 3506 of the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35) requires that the Office of Management and Budget (OMB) provide interested Federal agencies and the public an early opportunity to comment on information collection requests. OMB may amend or waive the requirement for public consultation to the extent that public participation in the approval process would defeat the purpose of the information collection, violate State or Federal law, or substantially interfere with any agency's ability to perform its statutory obligations. The IC Clearance Official, Regulatory Information Management Services, Office of Management, publishes that notice containing proposed information collection requests prior to submission of these requests to OMB. Each proposed information collection, grouped by office, contains the following: (1) Type of review requested, e.g. new, revision, extension, existing or reinstatement; (2) Title; (3) Summary of the collection; (4) Description of the need for, and proposed use of, the information; (5) Respondents and frequency of collection; and (6) Reporting and/or Recordkeeping burden. OMB invites public comment.

Dated: October 27, 2009.

Angela C. Arrington,

Director, Information Collection Clearance Division, Regulatory Information Management Services, Office of Management.

Federal Student Aid

Type of Review: New.

Title: Student Assistance General Provisions Non-Title IV Revenue Requirements (90/10).

Frequency: Annually.

Affected Public: Businesses or other for-profit.

Reporting and Recordkeeping Hour Burden:

Responses: 2,058.

Burden Hours: 3,087.

Abstract: The regulations establish the requirements under which a proprietary institution of higher education must derive at least ten percent of its annual revenue from resources other than Title IV HEA funds, and implements the Net Present Value formula and its alternative calculation prescribed by the statute and implemented through these regulations.

Requests for copies of the information collection submission for OMB review may be accessed from *http://edicsweb.ed.gov,* by selecting the ''Browse Pending Collections'' link and by clicking on link number 4076. When you access the information collection, click on ''Download Attachments '' to view. Written requests for information should be addressed to U.S. Department of Education, 400 Maryland Avenue, SW., LBJ, Washington, DC 20202–4537. Requests may also be electronically mailed to the Internet address *ICDocketMgr@ed.gov* or faxed to 202–401–0920. Please specify the complete title of the information collection when making your request.

Comments regarding burden and/or the collection activity requirements should be electronically mailed to *ICDocketMgr@ed.gov.* Individuals who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339.

[FR Doc. E9–26232 Filed 10–29–09; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF EDUCATION

Submission for OMB Review; Comment Request

AGENCY: Department of Education.

SUMMARY: The Director, Information Collection Clearance Division, Regulatory Information Management Services, Office of Management invites comments on the submission for OMB review as required by the Paperwork Reduction Act of 1995.

DATES: Interested persons are invited to submit comments on or before November 30, 2009.

ADDRESSES: Written comments should be addressed to the Office of Information and Regulatory Affairs, *Attention:* Education Desk Officer, Office of Management and Budget, 725 17th Street, NW., Room 10222, New Executive Office Building, Washington, DC 20503, be faxed to (202) 395–5806 or send e-mail to *oira_submission@omb.eop.gov.*

SUPPLEMENTARY INFORMATION: Section 3506 of the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35) requires that the Office of Management and Budget (OMB) provide interested Federal agencies and the public an early opportunity to comment on information collection requests. OMB may amend or waive the requirement for public consultation to the extent that public participation in the approval process would defeat the purpose of the information collection, violate State or Federal law, or substantially interfere with any agency's ability to perform its statutory obligations. The IC Clearance Official, Regulatory Information Management Services, Office of Management, publishes that notice containing proposed information collection requests prior to submission of these requests to OMB. Each proposed information collection, grouped by office, contains the following: (1) Type of review requested, e.g. new, revision, extension, existing or reinstatement; (2) Title; (3) Summary of the collection; (4) Description of the need for, and proposed use of, the information; (5) Respondents and frequency of collection; and (6) Reporting and/or Recordkeeping burden. OMB invites public comment.

Dated: October 27, 2009.

Angela C. Arrington,

Director, Information Collection Clearance Division, Regulatory Information Management Services, Office of Management.

Federal Student Aid

Type of Review: New.

Title: General Provisions Readmission for Service Members.

Frequency: On Occasion.

Affected Public: Individuals or household, not-for-profit institutions and State, Local, or Tribal Gov't, SEAs or LEAs.

Reporting and Recordkeeping Hour Burden:

Responses: 4,512.

Burden Hours: 1,513.

Abstract: The regulations establish the requirements under which an institution must readmit servicemembers with the same academic status they had at the institution when they last attended before being called to uniformed service.

Requests for copies of the information collection submission for OMB review may be accessed from *http://edicsweb.ed.gov,* by selecting the ''Browse Pending Collections'' link and by clicking on link number 4075. When you access the information collection, click on ''Download Attachments '' to view. Written requests for information should be addressed to U.S. Department of Education, 400 Maryland Avenue, SW., LBJ, Washington, DC 20202–4537. Requests may also be electronically mailed to the Internet address *ICDocketMgr@ed.gov* or faxed to 202–401–0920. Please specify the complete title of the information collection when making your request.

Comments regarding burden and/or the collection activity requirements should be electronically mailed to *ICDocketMgr@ed.gov.* Individuals who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339.

[FR Doc. E9–26233 Filed 10–29–09; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF ENERGY

National Nuclear Security Administration

Notice of Availability of the Draft Site-Wide Environmental Impact Statement for the Y–12 National Security Complex

AGENCY: National Nuclear Security Administration, U.S. Department of Energy.

ACTION: Notice of availability and public hearings.

SUMMARY: The National Nuclear Security Administration (NNSA), a separately-organized agency within the Department of Energy (DOE), announces the availability of the Draft Site-Wide Environmental Impact Statement for the Y–12 National Security Complex (Draft Y–12 SWEIS, DOE/EIS–0387). The Draft Y–12 SWEIS analyzes the potential environmental impacts of reasonable alternatives for ongoing and foreseeable future operations, facilities, and activities at Y–12. Five alternatives are analyzed: No Action Alternative (maintain the status quo); Uranium Processing Facility (UPF) Alternative; Upgrade-in-Place Alternative; Capability-sized UPF Alternative; and No Net Production/Capability-sized UPF Alternative. DOE NNSA has prepared the Draft Y–12 SWEIS in accordance with the *National Environmental Policy Act* (NEPA), the Council on Environmental Quality (CEQ) regulations that implement the procedural provisions of NEPA (40 CFR Parts 1500–1508), and DOE regulations implementing NEPA (10 CFR Part 1021). The CEQ regulations allow an agency to identify its preferred alternative or alternatives, if one or more exist, in a draft EIS (40 CFR 1502.14[e]). For the Draft Y–12 SWEIS, the Capability-sized UPF Alternative is the preferred alternative.

DATES: DOE NNSA invites comments on the Draft Y–12 SWEIS during the public comment period, which ends on January 4, 2010. DOE NNSA will consider comments received after this date to the extent practicable as it prepares the Final Y–12 SWEIS.

DOE NNSA will hold two public hearings on the Draft Y–12 SWEIS at the following location, dates, and times:

Oak Ridge, Tennessee, New Hope Center, 602 Scarboro Road (Corner of Scarboro Road and Second Street), Oak Ridge, Tennessee, Tuesday, November 17, 2009, 6:30 p.m.–9 p.m. and Wednesday, November 18, 2009, 10 a.m.–12:30 p.m.

ADDRESSES: Requests for additional information on the Draft Y–12 SWEIS, including requests for copies of the document, should be directed to: Ms. Pam Gorman, Y–12 SWEIS Document Manager, Y–12 Site Office, 800 Oak Ridge Turnpike, Suite A–500, Oak Ridge, TN 37830, or by *Telephone:* 865–576–9903. Written comments on the Draft Y–12 SWEIS should be submitted to the above address, by facsimile to 865–483–2014, or by electronic mail to *y12sweis.comments@tetratech.com.* Please mark correspondence ''Draft Y–12 SWEIS Comments.'' Additional information on the Y–12 SWEIS may be found at *http://www.y12sweis.com.*

For general information regarding the DOE NEPA process contact: Ms. Carol M. Borgstrom, Director, Office of NEPA Policy and Compliance, GC–20, U.S. Department of Energy, 1000 Independence Ave., SW., Washington, DC 20585, telephone 202–586–4600, or leave a message at 1–800–472–2756. Additional information regarding DOE NEPA activities and access to many of DOE's NEPA documents are available on the Internet through the DOE NEPA Web site at *http://www.gc.energy.gov/nepa.*

SUPPLEMENTARY INFORMATION:

Background. Y–12 is one of three primary installations on the DOE Oak Ridge Reservation in Oak Ridge, Tennessee. The other installations are the Oak Ridge National Laboratory and the East Tennessee Technology Park (formerly the Oak Ridge K–25 Site). Construction of Y–12 started in 1943 as part of the World War II Manhattan Project. The early missions of the site included the separation of uranium-235 from natural uranium by the electromagnetic separation process and the manufacture of nuclear weapons components from uranium and lithium. Today, as one of the DOE NNSA major production facilities, Y–12 is the primary site for enriched uranium processing and storage, and one of the primary manufacturing facilities for maintaining the U.S. nuclear weapons stockpile. Y–12 is unique in that it is the only source of secondaries, cases, and other nuclear weapons components within the DOE NNSA nuclear security enterprise. Y–12 also dismantles weapons components, safely and securely stores and manages special nuclear material (SNM), supplies SNM for use in naval and research reactors, and dispositions surplus materials. Y–12 nuclear nonproliferation programs play a critical role in securing our nation and the globe and combating the spread of weapons of mass destruction by removing, securing, and dispositioning SNM.

In the mid-1990s, DOE prepared several programmatic environmental impact statements (PEISs) to inform decisionmakers and the public on the potential environmental impacts of alternatives for carrying out its national security missions. DOE then made a number of decisions related to the nuclear security enterprise operations at Y–12 and the long-term storage and disposition of fissile material. Specifically, DOE decided that the mission of Y–12 would not change, and that Y–12 would continue to maintain the capability and capacity to fabricate nuclear weapons secondaries, cases, and limited-life components in support of the nuclear weapons stockpile, and store/process non-surplus, highly enriched uranium (HEU) long-term, and store surplus HEU pending disposition.

Most recently, DOE NNSA prepared the *Complex Transformation Supplemental PEIS* (SPEIS) (DOE/EIS–0236–S4) to analyze potential environmental impacts of alternatives for transforming the nuclear weapons complex into a smaller, more efficient enterprise. In the record of decision (ROD) for that SPEIS, DOE NNSA affirmed that manufacturing and research and development (R&D)

involving uranium will remain at Y–12 (73 FR 77644, December 19, 2008). DOE NNSA also announced that it will construct and operate a UPF at Y–12 as a replacement for existing facilities that are more than 50 years old and face significant safety and maintenance challenges to their continued operation. The DOE NNSA committed to evaluating the site-specific potential environmental impacts associated with continued production operations at Y–12 in this SWEIS, including those related to construction and operation of a UPF.

The continued operation of Y–12 is critical to DOE NNSA's Stockpile Stewardship Program and to preventing the spread and use of nuclear weapons worldwide. However, continued operation of Y–12 is made more difficult by the fact that most of the facilities at Y–12 are old, oversized, and inefficient. Continued long-term reliance on World War II-era facilities originally designed for other purposes, and on support facilities built in some cases to be temporary, would not meet DOE NNSA's objectives to transform its Y–12 infrastructure into one that is more responsive to future national security needs, less costly and more efficient to operate, and improve the level of security and safeguards necessary for future activities. Over time, nearly all Y–12 facilities will need to be replaced with structures designed for their intended present-day use. Modernizing this old, over-sized, and inefficient infrastructure is a key strategic goal of DOE NNSA and is consistent with strategic planning initiatives and prior programmatic NEPA documents.

In this SWEIS, DOE NNSA is considering alternatives that would support decisions for the modernization of Y–12, and implement the Complex Transformation SPEIS decisions. These Y–12 modernization alternatives would: (1) Improve the level of security and safeguards; (2) replace/upgrade end-of-life facilities and ensure a reliable enriched uranium processing capability to meet the mission of DOE NNSA; (3) improve efficiency of operations and reduce operating costs by consolidating and modernizing equipment and operation; (4) reduce the size of the Protected Area by 90 percent and reduce the operational cost necessary to meet the security requirements; (5) improve worker protection with an emphasis on incorporating engineered controls; and (6) comply with modern building codes and environment, safety, and health standards.

DOE NNSA conducted a public scoping process that began with the publication of a Notice of Intent (NOI) in the **Federal Register** on November 28, 2005 (70 FR 71270), in which DOE NNSA announced its intention to prepare a SWEIS and invited public comment on the scope of the NEPA review. The NOI also announced the schedule for public scoping meetings that were held on December 15, 2005, in Oak Ridge, Tennessee. In addition to the meetings, the public was encouraged to provide comments via mail, e-mail, and fax. All comments received during the public scoping period were considered by DOE NNSA in preparing the Draft Y–12 SWEIS. DOE's development and analysis of alternatives for the Draft Y–12 SWEIS reflect consideration of these comments.

DOE NNSA had originally planned to issue the Draft Y–12 SWEIS in late 2006; however, in October 2006, DOE NNSA decided to prepare the Complex Transformation SPEIS. As a result, DOE NNSA decided to delay the Draft Y–12 SWEIS until programmatic decisions on the Complex Transformation SPEIS were made.

Alternatives. The Y–12 SWEIS assesses the following five alternatives:

No Action Alternative. The No Action Alternative reflects the current nuclear weapons program missions at Y–12 and includes the manufacture and assembly/disassembly of weapons components, the continued processing and storage of enriched uranium materials, disposition of excess materials, and the continued removal of excess buildings and infrastructure. Under the No Action Alternative, DOE NNSA would consolidate the storage of enriched uranium into the Highly Enriched Uranium Materials Facility (HEUMF). The No Action Alternative includes continued operations related to other national security programs, such as nonproliferation, the Global Threat Reduction Initiative, and support to the Naval Reactors program. Additionally, there are many non-DOE NNSA activities at Y–12 that would also continue under this alternative. Under the No Action Alternative, DOE NNSA would make only those repairs and improvements to existing HEU processing facilities necessary to maintain existing levels of operation and to support essential worker safety and health requirements. Construction of a UPF and Complex Command Center (CCC) would not occur under the No Action Alternative.

Uranium Processing Facility (UPF) Alternative. Under this alternative, DOE NNSA would continue the No Action Alternative, and construct and operate a UPF and CCC. The UPF (388,000 square feet) would consolidate existing enriched uranium operations from multiple facilities into an integrated manufacturing operation. Under this alternative, the UPF would be sited adjacent to the HEUMF to allow the two facilities to function as one integrated HEU complex. Transition of the enriched uranium production operations to the UPF and transition of enriched uranium storage operations into the HEUMF would enable the creation of a new high-security area 90 percent smaller than the current high security protected area. The CCC would house equipment and personnel for emergency operations.

Upgrade-in-Place Alternative. Under this alternative, DOE NNSA would continue the No Action Alternative and upgrade the existing HEU and non-nuclear processing facilities to contemporary environmental, safety, and security standards to the extent possible within the limitations of the existing structures and without prolonged interruptions of manufacturing operations. Under this alternative there would be no UPF and parts of the current high-security area would not be downsized. Although existing production facilities would be modernized, it would not be possible to attain the combined level of safety, security and efficiency made possible by the UPF Alternative. Although an upgrade of existing facilities was not selected in the Complex Transformation SPEIS ROD, the Upgrade-in-Place Alternative is included as a reasonable alternative because it would correct to the extent possible within the limitations of the existing structures facility deficiencies associated with the existing enriched uranium and non-nuclear processing facilities, and could potentially require smaller upfront capital expenditures than the construction of a UPF. The construction of the CCC would also take place under this alternative.

Capability-Sized UPF Alternative. Under this alternative, DOE NNSA would continue the No Action Alternative but would reduce the capacity of enriched uranium operations. DOE NNSA would maintain a basic manufacturing capability to conduct surveillance and produce and dismantle secondaries and cases. To support this alternative, DOE NNSA would build a smaller UPF (350,000 square feet) compared to the UPF described under the UPF Alternative (388,000 square feet). A smaller UPF would maintain all capabilities for fabricating secondaries and cases, and capabilities for planned dismantlement, surveillance and uranium work for other DOE NNSA and non-DOE NNSA customers. The CCC would also be constructed under this alternative.

No Net Production/Capability-Sized UPF Alternative. Under a No Net Production/Capability-Sized UPF Alternative, DOE NNSA would maintain the capability to conduct surveillance and produce and dismantle secondaries and cases; however, under this alternative, DOE NNSA would not add new types or increased numbers of secondaries to the stockpile. This alternative would involve an even further reduction of production throughput at Y–12 compared to the Capability-Sized UPF Alternative. To support this alternative, DOE NNSA would build the smaller UPF (approximately 350,000 square feet) compared to the UPF described under the UPF Alternative (388,000 square feet). The CCC, described in Section S.1.4.2.2, would also be constructed under this alternative.

Public Hearings and Invitation to Comment. DOE NNSA will hold two public hearings on the Draft Y–12 SWEIS. The hearings will be held at the following location, dates, and times: Oak Ridge, Tennessee, New Hope Center, 602 Scarboro Road (Corner of Scarboro Road and Second Street), Oak Ridge, Tennessee, Tuesday, November 17, 2009, 6:30 p.m.–9 p.m. and Wednesday, November 18, 2009, 10 a.m.–12:30 p.m.

Individuals who would like to present comments orally at these hearings must register upon arrival at the hearing. Speaking time will be allotted by the hearing moderator to each individual wishing to speak so as to ensure that as many people as possible have the opportunity to speak. DOE NNSA representatives will be available to discuss the Draft Y–12 SWEIS and answer questions during the first half hour of the hearing. DOE NNSA will then hold a plenary session during which representatives will explain the Draft Y–12 SWEIS and the analyses in it. Following the plenary session, the public will have an opportunity to provide oral and written comments. Oral comments from the hearings and written comments submitted during the comment period will be considered by DOE NNSA in preparing the Final Y–12 SWEIS.

The Draft Y–12 SWEIS and additional information regarding Y–12 are available on the Internet at *http://www.Y12.doe.gov* and *http://www.Y12sweis.com.* The Draft Y–12 SWEIS and references are available for review by the public at the DOE Reading Rooms listed below:

U.S. Department of Energy, FOIA/Privacy Act Group, 1000 Independence Avenue, SW., Washington, DC 20585, *Phone:* (202) 586–3142.

Paducah Gaseous Diffusion Plant, Department of Energy, Environmental Information Center and Reading Room, 115 Memorial Drive, Barkley Centre, Paducah, Kentucky 42001, *Phone:* (270) 554–6979.

Oak Ridge Operations Office, DOE Oak Ridge Information Center, 475 Oak Ridge Turnpike, Oak Ridge, Tennessee 37830, *Phone:* (865) 241–4780 or (toll-free) 1 (800) 382–6938, option 6.

Portsmouth Gaseous Diffusion Plant, Department of Energy, Environmental Information Center, 1862 Shyville Rd., Room 220, Piketon, Ohio 45661.

Following the end of the public comment period on the Draft SWEIS described above, the DOE NNSA will consider and respond to the comments received, and issue the Final Y–12 SWEIS. The DOE NNSA will consider the environmental impact analysis presented in the Final Y–12 SWEIS, along with other information, in making its decisions related to operations at Y–12.

Signed in Washington, DC, on October 22, 2009.

Thomas P. D'Agostino,

Administrator, National Nuclear Security Administration.

[FR Doc. E9–26207 Filed 10–29–09; 8:45 am]

BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OW–2009–0817; FRL–8975–8]

Agency Information Collection Activities; Proposed Collection; Comment Request; Stormwater Management Including Discharges From Newly Developed and Redeveloped Sites; EPA ICR No. 2366.01, OMB Control No. 2040–NEW.

AGENCY: Environmental Protection Agency.

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 *et seq.*), this document announces that EPA is planning to submit a request for a new Information Collection Request (ICR) to the Office of Management and Budget (OMB). Before submitting the ICR to OMB for review and approval, EPA is soliciting comments on specific aspects of the proposed information collection as described below.

DATES: Comments must be submitted on or beforeDecember 29, 2009.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OW–2009–0817, by one of the following methods:

- *www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *E-mail: OW–Docket@epa.gov*, Attention Docket ID No. EPA–HQ–OW–2009–0817.
- *Fax:* 202–566–9744.
- *Mail:* Water Docket, U.S. Environmental Protection Agency, Mail code: 4203M, 1200 Pennsylvania Ave., NW., Washington, DC 20460. Attention Docket ID No. EPA–HQ–OW–2009–0817.
- *Hand Delivery:* Water Docket, EPA Docket Center, EPA West Building Room 3334, 1301 Constitution Ave., NW., Washington, DC, Attention Docket ID No. EPA–HQ–OW–2009–0817. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–HQ–OW–2009–0817. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *www.regulations.gov* or e-mail. The *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 e-mail comment directly to EPA without going through *www.regulations.gov* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

FOR FURTHER INFORMATION CONTACT: Jan Matuszko, Engineering and Analysis Division, Office of Water, (4303T), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460; *telephone number:* 202–566–1035; *fax number:* 202–566–1053; *e-mail address: matuszko.jan@epa.gov* or Jonathan Angier, Water Permits Division, (4203M), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460; *telephone number:* 202–564–0729; *fax number:* 202–564–6392; *e-mail address: angier.jonathan@epa.gov.*

SUPPLEMENTARY INFORMATION:

How Can I Access the Docket and/or Submit Comments?

EPA has established a public docket for this ICR under Docket ID No. EPA–HQ–OW–2009–0817, which is available for online viewing at *www.regulations.gov*, or in person viewing at the Water Docket in the EPA Docket Center (EPA/DC), EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC. The EPA/DC 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 Reading Room is 202–566–1744, and the telephone number for the Water Docket is 202–566–2426.

Use *www.regulations.gov* to obtain a copy of the draft collection of information, submit or view public comments, access the index listing of the contents of the docket, and to access those documents in the public docket that are available electronically. Once in the system, select ''search,'' then key in the docket ID number identified in this document.

What Information Is EPA Particularly Interested in?

Pursuant to section 3506(c)(2)(A) of the PRA, EPA specifically solicits comments and information to enable it to:

(i) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information will have practical utility;

(ii) evaluate the accuracy of the Agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

(iii) enhance the quality, utility, and clarity of the information to be collected; and

(iv) minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses. In particular, EPA is requesting comments from very small businesses (those that employ less than 25) on examples of specific additional efforts that EPA could make to reduce the paperwork burden for very small businesses affected by this collection.

What Should I Consider When I Prepare My Comments for EPA?

You may find the following suggestions helpful for preparing your comments:

1. Explain your views as clearly as possible and provide specific examples.
2. Describe any assumptions that you used.
3. Provide copies of any technical information and/or data you used that support your views.
4. If you estimate potential burden or costs, explain how you arrived at the estimate that you provide.
5. Offer alternative ways to improve the collection activity.
6. Make sure to submit your comments by the deadline identified under DATES.
7. To ensure proper receipt by EPA, be sure to identify the docket ID number assigned to this action in the subject line on the first page of your response. You may also provide the name, date, and **Federal Register** citation.

What Information Collection Activity or ICR Does This Apply to?

Docket ID No. EPA–HQ–2009–0817

Affected entities: EPA is proposing to distribute three separate questionnaires focusing on gathering data pertaining to current stormwater management practices, including those used to control discharges from newly developed and redeveloped sites. The first questionnaire (''Industry Questionnaire'') targets establishments that develop and redevelop sites in the United States. Establishments receiving this questionnaire are classified by the following eight North American Industry Classification System (NAICS) codes:

236115: New Single-Family Housing Construction (except operative builders);

236116: New Multifamily Housing Construction (except operative builders);

236117: New Housing Operative Builders;

236210: Industrial Building Construction;

236220: Commercial and Institutional Building Construction;

237210: Land Subdivision;

237310: Highway, Street and Bridge Construction; and

237990: Other Heavy and Civil Engineering Construction.

The second questionnaire (''MS4 Questionnaire'') targets owners or operators of municipal separate storm sewer systems (MS4s). This includes MS4 communities regulated under NPDES stormwater Phase I and Phase II regulations and other local government entities.

Lastly, EPA designed the third questionnaire (''States Questionnaire'') to obtain information from the states and territories.

Title: Information Collection Request for Stormwater Management Including Discharges from Newly Developed and Redeveloped Sites.

ICR numbers: EPA ICR No. 2366.01, OMB Control No. 2040–NEW.

ICR status: This ICR is for a new information collection activity. 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 EPA's regulations in title 40 of the CFR, after appearing in the **Federal Register** when approved, are listed in 40 CFR part 9, are displayed either by publication in the **Federal Register** or by other appropriate means, such as on the related collection instrument or form, if applicable. The display of OMB control numbers in certain EPA regulations is consolidated in 40 CFR part 9.

Abstract: As the urban, suburban and exurban human environment expands, there is an increase in impervious land cover and stormwater discharges. This increase in impervious land cover on developed sites reduces or eliminates the natural infiltration of precipitation. The resulting stormwater flows across roads, rooftops, and other impervious surfaces, picking up pollutants that are then discharged to our nation's waters. In addition, the increased volume of stormwater discharges results in the scouring of rivers and streams, degrading the physical integrity of aquatic habitats, stream function and overall water quality.

In order to make EPA's stormwater program more effective in protecting our nation's water quality, EPA commissioned the National Research Council (NRC) to review the Agency's program for controlling stormwater discharges under the CWA and recommend any steps the Agency should take. The NRC released its report, entitled *Urban Stormwater Management in the United States*, National Academy of Sciences Press, in October 2008, with recommendations for EPA on how to strengthen the national stormwater program (available at *http://cfpub.epa.gov/npdes/home.cfm?program_id=6*). The NRC found that the current regulatory approach by EPA under the CWA is not adequately controlling all sources of stormwater discharge that are contributing to waterbody impairment. The NRC recommended that EPA address stormwater discharges from impervious land cover and promote practices that harvest, infiltrate and evapotranspirate stormwater to reduce or prevent it from being discharged, which is critical to reducing the volume and pollutant loading to our nation's waters.

In order to protect our nation's water quality, EPA is committing to move forward with a nationwide rulemaking pursuant to CWA section 402(p), 33 U.S.C. 1342(p), to propose requirements, including design or performance standards, for stormwater discharges from, at minimum, newly developed and redeveloped sites. EPA intends to propose regulatory options that would revise the NPDES regulations and establish a comprehensive program to address stormwater discharges from newly developed and redeveloped sites and to take final action no later than November 2012. As part of this effort, EPA needs to gather data to assess current practices and regulatory mechanisms; the effectiveness and feasibility of various control technologies, best management practices (BMPs), and pollution prevention opportunities and their associated potential pollutant reductions and costs; and the possible financial impacts associated with implementing regulations for stormwater discharges in developed and developing areas. Therefore, EPA is seeking Office of Management and Budget (OMB) approval for an ICR.

In order to evaluate current stormwater management practices, the scope of the current state and local programs, and any EPA regulation to control these discharges, EPA is proposing several data collection activities. Because a regulation could impact, among others, establishments responsible for developing or redeveloping sites, MS4s, and the states, the ICR announced today is composed of three questionnaires: an Industry Questionnaire, an MS4 Questionnaire, and a State Questionnaire.

EPA is distributing the Industry Questionnaire to collect technical feasibility, effectiveness, and cost information on various controls, pollution prevention technologies, and BMPs applied to stormwater discharges from newly developed and redeveloped sites. Some of these BMPs include promoting onsite stormwater retention. This information will be used to assist EPA in evaluating various regulatory options and determining the site level and nationwide costs for regulating the pollutant discharges associated with stormwater from newly developed and redeveloped sites. Additionally, EPA will collect firm level financial data to assess the economic impact if these controls were the basis of a regulation.

The MS4 and State Questionnaires will collect information on the scope of the current regulatory program and the stormwater management practices that are currently required for controlling stormwater discharges. This includes information on site plan review, performance standards or design criteria, retention practices and associated financial information. EPA intends to use this information to assess existing conditions and the impact to MS4s and states that may result from a regulation.

EPA intends to submit this information collection request to the Office of Management and Budget (OMB) for approval to distribute three mandatory questionnaires under the authority of Section 308 of the CWA, 33 U.S.C. 1318. All questionnaire recipients will be required to complete and return the questionnaire to EPA.

EPA solicits comment on the following items regarding this ICR.

(1) Are there alternate means of gathering data from the MS4s and/or States that would obviate the need for a questionnaire?

(2) Are there other commercial enterprises that should be included as respondents, as a means of obtaining maintenance and installation cost information for stormwater controls?

(3) Are there alternate means of gathering information on general project design and costs, and the changes in general project design and costs that could result from implementing national standards for stormwater discharges from newly developed and redeveloped sites?

(4) Are there alternate means of distributing the ''Industry Questionnaire'' in order to get representative information while causing less burden to the respondents, such as a short questionnaire that goes out to a larger sample of respondents while a smaller subset of respondents receives a more detailed questionnaire?

Burden Statement: The annual public reporting and recordkeeping burden for this collection of information is estimated to average 53 hours per response. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements which have subsequently changed; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

The ICR provides a detailed explanation of the Agency's estimate, which is only briefly summarized here:

Estimated total number of potential respondents: 2,060.

Frequency of response: One occasion.

Estimated total average number of hours for each respondent: 53.

Estimated total annual burden hours: 108,675.

Estimated total annual costs: $4.07 million. This includes an estimated burden cost of $4.05 million for labor and $17,150 for operations and maintenance.

What Is the Next Step in the Process for This ICR?

EPA will consider the comments received and amend the ICR as appropriate. The final ICR package will then be submitted to OMB for review and approval pursuant to 5 CFR 1320.12. At that time, EPA will issue another **Federal Register** notice pursuant to 5 CFR 1320.5(a)(1)(iv) to announce the submission of the ICR to OMB and the opportunity to submit additional comments to OMB. If you have any questions about this ICR or the approval process, please contact the technical person listed under **FOR FURTHER INFORMATION CONTACT**.

Dated: October 26, 2009.

Ephraim S. King,

Director, Office of Science and Technology.

[FR Doc. E9–26169 Filed 10–29–09; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[ER–FRL–8798–8]

Environmental Impact Statements and Regulations; Availability of EPA Comments

Availability of EPA comments prepared pursuant to the Environmental Review Process (ERP), under section 309 of the Clean Air Act and Section 102(2)(c) of the National Environmental Policy Act as amended. Requests for copies of EPA comments can be directed to the Office of Federal Activities at 202–564–7146 or *http://www.epa.gov/compliance/nepa/.*

An explanation of the ratings assigned to draft environmental impact statements (EISs) was published in FR dated July 17, 2009 (74 FR 34754).

Draft EISs

EIS No. 20090290, ERP No. D–FTA–F54014–WI, Kenosha-Racine-Milwaukee Commuter Rail Extension, Alternative Analysis, U.S. COE Section 404 Permit, Funding, Kenosha, Racine, and Milwaukee Counties, WI.

Summary: EPA expressed environmental concerns about impacts to wetlands and natural areas, and requested additional information on hazardous waste, noise and vibration. Rating EC2.

EIS No. 20090296, ERP No. D–SFW–K90033–CA, Sears Point Wetland and Watershed Restoration Project, To Restore Tidal Wetlands and Rehabilitate Diked Wetlands, Sonoma County, CA.

Summary: EPA expressed environmental concerns about impacts to wetlands and waters from construction activities (trails, roads, and utilities) not related to wetland restoration and to air quality from construction diesel emissions. Rating EC2.

EIS No. 20090107, ERP No. DS–NRS–D36121–WV, Lost River Subwatershed of the Potomac River Watershed Project, Construction of Site 16 on Lower Cove Run and Deletion of Site 23 on Cullers Run in the Lost River Watershed, Change in Purpose for Site 16 and Updates Information Relative to Site 23, U.S. Army COE Section 404 Permit, Hardy County, WV.

Summary: EPA continues to have environmental concerns about impacts to a cold water stream and loss of wetland resources, and requested additional information on project need, current conditions of the study area and secondary impacts of a water distribution system. Rating EC2.

Final EISs

EIS No. 20090183, ERP No. F–NRC–D06006–PA, Generic—License Renewal of Nuclear Plants, Supplement 36 to NUREG–1437, Regarding Beaver Valley Power Station, Units 1 and 2, Plant Specific, Issuing Nuclear Power Plant Operating License for an Additional 20-Year Period, PA.

Summary: EPA has no objection to the proposed action.

EIS No. 20090218, ERP No. F–NRC–D06007–PA, GENERIC—License Renewal of Nuclear Plants, Supplement 37 NUREG–1437, Regarding Three Mile Island Nuclear Station, Unit 1, Dauphin County, PA.

Summary: EPA continues to have environmental concerns about construction impacts.

EIS No. 20090281, ERP No. F–BLM–J01083–WY, South Gillette Area Coal Lease Applications, WYW172585, WYW173360, WYW172657, WYW161248, Proposal to Lease Four Tracts of Federal Coal Reserves, Belle Ayr, Coal Creek, Caballo, and Cordero Rojo Mines, Wyoming Powder River Basin, Campbell County, WY.

Summary: No formal comment letter was sent to the preparing agency.

EIS No. 20090301, ERP No. FS–NRS–B36121–WV, Lost River Subwatershed of the Potomac River Watershed Project, Construction of Site 16 on Lower Cove Run and Deletion of Site 23 on Cullers Run in the Lost River Watershed, Change in Purpose for Site 16 and Updates Information Relative to Site 23, U.S. Army COE Section 404 Permit, Hardy County, WV.

Summary: EPA continues to have environmental concerns about wetland and cold water stream impacts, and requested additional information on current environmental conditions and the function of structures already in the watershed.

Dated: October 27, 2009.

Robert W. Hargrove,

Director, NEPA Compliance Division, Office of Federal Activities.

[FR Doc. E9–26218 Filed 10–29–09; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[ER–FRL–8598–7]

Environmental Impacts Statements; Notice of Availability

Responsible Agency: Office of Federal Activities, General Information (202) 564–1399 or *http://www.epa.gov/compliance/nepa/.*

Weekly receipt of Environmental Impact Statements

Filed 10/19/2009 through 10/23/2009

Pursuant to 40 CFR 1506.9.

EIS No. 20090359, Final EIS, FHW, MO, MO–63 Corridor Improvement Project, To Correct Roadway Deficiencies, Reduce Congestion and Provide Continuity along the MO–63 Corridor on the Existing Roadway and on New Location, Osage, Maries and Phelps Counties, MO, *Wait Period Ends:* 11/30/2009, *Contact:* Peggy Casey, 573–636–7104.

EIS No. 20090360, Draft EIS, NGB, VT, 158th Fighter Wing Vermont Air National Guard Project, Proposed Realignment of National Guard Avenue and Main Gate Construction, Burlington International Airport in South Burlington, VT, *Comment Period Ends:* 12/14/2009, *Contact:* Robert L. Dogan, 301–836–8859.

EIS No. 20090361, Final EIS, NOA, 00, PROGRAMMATIC—Toward an Ecosystem Approach for the Western Pacific Region: From Species-Based Fishery Management Plans to Place-Based Fishery Ecosystem Plans, Bottomfish and Seamount Groundfish, Coral Reef Ecosystems, Crustaceans, Precious Corals, Pelagics, Implementation, American Samoa, Commonwealth of the Northern Mariana Islands, Hawaii, U.S. Pacific Remote Island Area, *Wait Period Ends:* 11/30/2009, *Contact:* William L. Robinson, 808–944–2200.

EIS No. 20090362, Draft EIS, DOE, WA, Hanford Site Tank Closure and Waste Management Project, Implementation, Richland, Benton County, WA, *Comment Period Ends:* 03/19/2010, *Contact:* Mary Beth Burandi 888–829–6347.

EIS No. 20090363, Draft EIS, SFW, TX, Hays County Regional Habitat Conservation Plan, Application for an Incidental Take Permit, Hays County, TX, *Comment Period Ends:* 01/28/2010, *Contact:* Allison Arnold, 512–490–0057 Ext. 242.

EIS No. 20090364, Final EIS, NPS, SD, Wind Cave National Park Project, Elk General Management Plan, Implementation, Custer County, SD, *Wait Period Ends:* 11/30/2009, *Contact:* Nick Chevance, 402–661–1844.

EIS No. 20090365, Draft EIS, COE, CO, Moffat Collection System Project, to Provide High Quality Dependable, and Safe Drinking Water to Over 1.1 Million Customers in the City and County of Denver, Application for an Section 404 Permit, City and County Denver, Adams, Boulder, Jeffferson and Grand Counties, CO, *Comment*

Period Ends: 01/28/2010, *Contact:* Scott Franklin, 303–979–4120.

EIS No. 20090366, Final EIS, FHW, CO, US–36 Corridor, Multi-Modal Transportation Improvements between I–25 in Adams County and Foothills Parkway/Table Mesa Drive in Boulder, Adams, Denver, Broomfield, Boulder and Jefferson Counties, CO, *Wait Period Ends:* 11/30/2009, *Contact:* Monica Pavlik, 720–963–3012.

EIS No. 20090367, Draft EIS, USA, 00, Fort Bliss Army Growth and Force Structure Realignment Project, Implementing Land Use Changes and Improving Training Infrastructure to Support the Growth the Army (GTA) Stationing Decision, El Paso Country, TX and Dona Ana and Otero Counties, NM, *Comment Period Ends:* 12/30/2009, *Contact:* Jennifer Shore, 703–602–4238.

EIS No. 20090368, Draft EIS, NSA, TN, Y–12 National Security Complex Project, to Support the Stockpile Stewardship Program and to Meet the Mission Assigned to Y–12, Oak Ridge, TN, *Comment Period Ends:* 01/04/2010, *Contact:* Pam Gorman, 865–576–9903.

EIS No. 20090369, Draft EIS, USA, LA, Joint Readiness Training Center and Fort Polk Land Acquisition Program, Purchase and Lease Lands for Training and Management Activities, in the Parishes of Vernon, Sabine, Natchitoches, LA, *Comment Period Ends:* 12/14/2009, *Contact:* Kristin Evenstad, 703–692–6427.

EIS No. 20090370, Final EIS, NOA, 00, Amendment 16 to the Northwest Multispecies Fishery Management Plan, Propose to Adopt, Approval and Implementation Measures to Continue Formal Rebuilding Program for Overfishing and to End Overfishing on those Stock where it Occurring, Gulf of Maine, *Wait Period Ends:* 11/30/2009, *Contact:* Patricia A. Kurkul, 978–281–9200.

Amended Notices

EIS No. 20090312, Draft EIS, COE, OH, Cleveland Harbor Dredged Material Management Plan, Operations and Maintenance, Cuyahoga County, OH, *Comment Period Ends:* 12/07/2009, *Contact:* Frank O'Connor, 716–879–4131. Revision to FR Notice Published 09/11/2009: Extending Comment period from 10/26/2009 to 12/07/2009.

Dated: October 27, 2009.

Robert W. Hargrove,

Director, NEPA Compliance Division, Office of Federal Activities.

[FR Doc. E9–26179 Filed 10–29–09; 8:45 am]

BILLING CODE 6560–50–P

FARM CREDIT ADMINISTRATION

Farm Credit Administration Board Policy Statements

AGENCY: Farm Credit Administration.

ACTION: Notice.

SUMMARY: The Farm Credit Administration (FCA) is publishing the list of FCA Board policy statements, which includes three changes since its last publication and one policy statement in its entirety.

FOR FURTHER INFORMATION CONTACT: Wendy Laguarda, Assistant General Counsel, Office of General Counsel, Farm Credit Administration, 1501 Farm Credit Drive, McLean, Virginia 22102–5090, (703) 883–4020, TTY (703) 883–4020.

SUPPLEMENTARY INFORMATION: On November 25, 2005, we published a list of all current FCA Board policy statements and the text of each in their entirety. (*See* 70 FR 71142.) On June 13, 2006, we published just the list and stated that there were no changes. (*See* 71 FR 34132.) Since then, we published a revised policy statement (FCA–PS–62) (71 FR 46481, Aug. 14, 2006). The list being published today contains a revised policy statement (FCA–PS–79) which was originally published at 73 FR 9804, Feb. 22, 2008. We are publishing the text of policy statement FCA–PS–79 in its entirety.

You can view each policy statement online at *http://www.fca.gov/handbook.nsf*. The FCA will continue to publish new or revised policy statements in their full text.

FCA Board Policy Statements

FCA–PS–34 Disclosure of the Issuance and Termination of Enforcement Documents
FCA–PS–37 Communications During Rulemaking
FCA–PS–41 Alternative Means of Dispute Resolution
FCA–PS–44 Travel
FCA–PS–53 Examination Philosophy
FCA–PS–59 Regulatory Philosophy
FCA–PS–62 Equal Employment Opportunity Diversity
FCA–PS–64 Rules for the Transaction of Business of the Farm Credit Administration Board
FCA–PS–65 Release of Consolidated Reporting System Information
FCA–PS–67 Nondiscrimination on the Basis of Disability in Agency Programs and Activities
FCA–PS–68 FCS Building Association Management Operations Policies and Practices
FCA–PS–71 Disaster Relief Efforts by Farm Credit Institutions
FCA–PS–72 Financial Institution Rating System (FIRS)
FCA–PS–77 Borrower Privacy
FCA–PS–78 Official Names of Farm Credit System Institutions
FCA–PS–79 Consideration and Referral of Supervisory Strategies and Enforcement Actions

Consideration and Referral of Supervisory Strategies and Enforcement Actions

FCA–PS–79 [NV–09–16]

Effective Date: August 7, 2009.

Effect on Previous Action: Rescinds and supersedes the previous PS–79.

Source of Authority: Sections 5.19, 5.25–5.35 of the Farm Credit Act of 1971, as amended.

The FCA board hereby adopts the following policy statement:

The Farm Credit Administration (FCA or Agency) Board provides for the regulation and examination of Farm Credit System (System or FCS) institutions, which includes the Federal Agricultural Mortgage Corporation (Farmer Mac), in accordance with the Farm Credit Act of 1971, as amended (the "Act"). This policy addresses conditions that warrant referrals to the Agency's Regulatory Enforcement Committee (REC) to consider appropriate supervisory strategies and recommend to the FCA Board the use of the enforcement authorities conferred on the Agency under Part C, Title V of the Act or other statutes. Enforcement actions include formal agreements, orders to cease and desist, temporary orders to cease and desist, civil money penalties, suspensions or removals of directors or officers, and conditions imposed in writing to address unsafe or unsound practices or violations of law, rule or regulation (Enforcement Document). Taking these actions, in an appropriate and timely manner, is critical to maintaining shareholder, investor, and public confidence in the financial strength and future viability of the System.

This policy provides only internal FCA guidance. It is not intended to create any rights, substantive or procedural, enforceable at law or in any administrative proceeding.

Composition of the REC

The Chairman of the FCA Board will designate the Chief Operating Officer and the office directors of the Office of Examination, Office of General Counsel, and Office of Regulatory Policy, or the directors of successor offices, as voting members of the REC. A representative from the Farm Credit System Insurance Corporation will be invited to participate in REC activities as a non-voting member. The Chairman of the FCA Board will also designate one of the voting REC members as Chairman of the REC.

Due to the statutory independence of the Office of Secondary Market Oversight (OSMO), there will be different REC membership when considering issues related to Farmer Mac.

Referrals to the REC

Recommended supervisory strategies or enforcement actions concerning an FCS institution or person will be referred to the REC when any of the conditions exist, as specified below, or when a specified condition does not exist, but consideration of an enforcement action or review by the REC is appropriate. The REC will review the proposed actions and draft enforcement documents and assess the recommendations for pursuing any such actions. The REC may revise the recommendations and will document its concurrence or nonconcurrence with the supervisory strategy or enforcement action.

Conditions Warranting Referral to the REC

Any one of the following conditions requires a referral to the REC for its consideration of supervisory strategies or enforcement actions.

1. A ''4'' or ''5'' composite FIRS rating is assigned to an FCS institution;
2. The institution or person is deemed unable or unwilling to address a material: (a) Unsafe or unsound condition or practice; or (b) violation or ongoing violation of law or regulation;
3. The institution or person is about to engage in a material unsafe or unsound practice or is about to commit a willful or material violation of law or regulation that exposes the institution to significant risk;
4. Conditions meet the statutory criteria for a suspension or removal;
5. Conditions meet the statutory criteria for assessing a civil money penalty and the factors to be considered in determining the amount of a civil money penalty justify the imposition of the penalty;
6. Conditions meet the statutory criteria to place an FCS institution in conservatorship or receivership;
7. An institution or person fails to comply with an Enforcement Document or is unwilling or unable to address a violation of a condition imposed in writing; or
8. Conditions justify termination or modification of an existing Enforcement Document.

As appropriate, referrals for the REC's consideration also may be made for conditions not specified above.

Notification of the REC

The REC will be notified when any institution is assigned a ''3'' composite FIRS rating and informed of the Agency's supervisory strategies.

Consultation With the REC

For institutions under a formal Enforcement Document, or assigned a composite FIRS rating of ''4'' or ''5'', requests for prior approvals, or other actions, will be referred to the REC for consultation.

Referral to the FCA Board

The REC will refer to the FCA Board for its consideration all recommendations concurred with by the REC for the placement of an Enforcement Document on a FCS institution or person. In the unlikely instance, when an institution receives a composite ''4'' or ''5'' FIRS rating and a formal Enforcement Document is not recommended to the FCA Board, the REC will promptly document and report the Agency's supervisory strategy to the FCA Board.

Reporting to the FCA Board

The REC Chairman will report at least quarterly to the FCA Board if matters are referred to or reviewed by the REC, but FCA Board action is not subsequently requested.

Actions by the REC

The REC will develop procedures to address the responsibilities outlined herein.

Due to OSMO's statutory independence, the Director of OSMO will develop procedures for actions affecting Farmer Mac.

Dated this 7th day of August 2009 by order of the Board.

Signed by: Roland E. Smith, Secretary, Farm Credit Administration Board.

Dated: October 26, 2009.

Roland E. Smith,

Secretary, Farm Credit Administration Board.

[FR Doc. E9–26230 Filed 10–29–09; 8:45 am]

BILLING CODE 6705–01–P

FEDERAL COMMUNICATIONS COMMISSION

Federal Advisory Committee Act; Advisory Committee on Diversity for Communications in the Digital Age

AGENCY: Federal Communications Commission.

ACTION: Notice of public meeting.

SUMMARY: In accordance with the Federal Advisory Committee Act, this notice advises interested persons that the Federal Communications Commission's (FCC) Advisory Committee on Diversity for Communications in the Digital Age (''Diversity Committee'') will hold a meeting on December 3, 2009 at 2 p.m. in the Commission Meeting Room of the Federal Communications Commission, Room TW–C305, 445 12th Street, SW., Washington, DC 20554. This will be the third meeting of the full Diversity Committee under its renewed charter and new membership.

DATES: December 3, 2009.

ADDRESSES: Federal Communications Commission, Room TW–C305 (Commission Meeting Room), 445 12th Street, SW., Washington, DC 20554.

FOR FURTHER INFORMATION CONTACT: Barbara Kreisman, 202–418–1605; *Barbara.Kreisman@FCC.gov.*

SUPPLEMENTARY INFORMATION: At this meeting the Media Issues working group will present a formal best practices recommendation.

Members of the general public may attend the meeting. The FCC will attempt to accommodate as many people as possible. However, admittance will be limited to seating availability. The public may submit written comments before the meeting to: Barbara Kreisman, the FCC's Designated Federal Officer for the Diversity Committee by e-mail: *Barbara.Kreisman@fcc.gov* or U.S. Postal Service Mail (Barbara Kreisman, Federal Communications Commission, Room 2–A665, 445 12th Street, SW., Washington, DC 20554).

Open captioning will be provided for this event. Other reasonable accommodations for people with disabilities are available upon request. Requests for such accommodations should be submitted via e-mail to *fcc504@fcc.gov* or by calling the Consumer & Governmental Affairs Bureau at (202) 418–0530 (voice), (202) 418–0432 (tty). Such requests should include a detailed description of the accommodation needed. In addition, please include a way we can contact you if we need more information. Please allow at least five days advance notice; last minute requests will be accepted, but may be impossible to fill.

Additional information regarding the Diversity Committee can be found at *http://www.fcc.gov/DiversityFAC.*

Federal Communications Commission.

Barbara A. Kreisman,

Chief, Video Division, Media Bureau.

[FR Doc. E9–26226 Filed 10–29–09; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL RESERVE SYSTEM

Formations of, Acquisitions by, and Mergers of Bank Holding Companies

The companies listed in this notice have applied to the Board for approval, pursuant to the Bank Holding Company Act of 1956 (12 U.S.C. 1841 *et seq.*) (BHC Act), Regulation Y (12 CFR Part 225), and all other applicable statutes and regulations to become a bank holding company and/or to acquire the assets or the ownership of, control of, or the power to vote shares of a bank or bank holding company and all of the banks and nonbanking companies owned by the bank holding company, including the companies listed below.

The applications listed below, as well as other related filings required by the Board, are available for immediate inspection at the Federal Reserve Bank indicated. The applications also will be available for inspection at the offices of the Board of Governors. Interested persons may express their views in writing on the standards enumerated in the BHC Act (12 U.S.C. 1842(c)). If the proposal also involves the acquisition of a nonbanking company, the review also includes whether the acquisition of the nonbanking company complies with the standards in section 4 of the BHC Act (12 U.S.C. 1843). Unless otherwise noted, nonbanking activities will be conducted throughout the United States. Additional information on all bank holding companies may be obtained from the National Information Center website at *www.ffiec.gov/nic/*.

Unless otherwise noted, comments regarding each of these applications must be received at the Reserve Bank indicated or the offices of the Board of Governors not later than November 30, 2009.

A. Federal Reserve Bank of St. Louis (Glenda Wilson, Community Affairs Officer) P.O. Box 442, St. Louis, Missouri 63166–2034:

1. First National Security Company, Hot Springs, Arkansas; to acquire 100 percent of the voting shares of Heritage Capital Corporation, and thereby indirectly acquire voting shares of Heritage Bank, both of Jonesboro, Arkansas.

B. Federal Reserve Bank of Kansas City (Todd Offenbacker, Assistant Vice President) 1 Memorial Drive, Kansas City, Missouri 64198–0001:

1. Stockmens Financial Corporation and Stockmens Limited Partnership, both of Rapid City, South Dakota; to acquire 100 percent of the voting shares of Valentine Bancorporation, and thereby indirectly acquire voting shares of First National Bank of Valentine, both of Valentine, Nebraska.

Board of Governors of the Federal Reserve System, October 27, 2009.

Robert deV. Frierson,

Deputy Secretary of the Board.

[FR Doc. E9–26166 Filed 10–29–09; 8:45 am]

BILLING CODE 6210–01–S

FEDERAL RESERVE SYSTEM

Notice of Proposals to Engage in Permissible Nonbanking Activities or to Acquire Companies that are Engaged in Permissible Nonbanking Activities

The companies listed in this notice have given notice under section 4 of the Bank Holding Company Act (12 U.S.C. 1843) (BHC Act) and Regulation Y (12 CFR Part 225) to engage *de novo*, or to acquire or control voting securities or assets of a company, including the companies listed below, that engages either directly or through a subsidiary or other company, in a nonbanking activity that is listed in § 225.28 of Regulation Y (12 CFR 225.28) or that the Board has determined by Order to be closely related to banking and permissible for bank holding companies. Unless otherwise noted, these activities will be conducted throughout the United States.

Each notice is available for inspection at the Federal Reserve Bank indicated. The notice also will be available for inspection at the offices of the Board of Governors. Interested persons may express their views in writing on the question whether the proposal complies with the standards of section 4 of the BHC Act. Additional information on all bank holding companies may be obtained from the National Information Center website at *www.ffiec.gov/nic/*.

Unless otherwise noted, comments regarding the applications must be received at the Reserve Bank indicated or the offices of the Board of Governors not later than November 16, 2009.

A. Federal Reserve Bank of Chicago (Colette A. Fried, Assistant Vice President) 230 South LaSalle Street, Chicago, Illinois 60690–1414:

Ida Grove Bancshares, Inc., Ida Grove, Iowa; to engage *de novo* in leasing personal or real property, pursuant to section 225.28(b)(3) of Regulation Y.

Board of Governors of the Federal Reserve System, October 27, 2009.

Robert deV. Frierson,

Deputy Secretary of the Board.

[FR Doc. E9–26167 Filed 10–29–09; 8:45 am]

BILLING CODE 6210–01–S

FEDERAL MARITIME COMMISSION

Notice of Agreement Filed

The Commission hereby gives notice of the filing of the following agreement under the Shipping Act of 1984. Interested parties may submit comments on the agreement to the Secretary, Federal Maritime Commission, Washington, DC 20573, within ten days of the date this notice appears in the **Federal Register**. A copy of the agreement is available through the Commission's Web site (*http://www.fmc.gov*) or by contacting the Office of Agreements at (202) 523–5793 or *tradeanalysis@fmc.gov*.

Agreement No.: 012063–002.

Title: Grand Alliance/Zim Transpacific Vessel Sharing Agreement.

Parties: Hapag-Lloyd Aktiengesellschaft; Nippon Yusen Kaisha; Orient Overseas Container Line Limited; and Zim Integrated Shipping Services Limited.

Filing Party: Wayne R. Rohde, Esq., Sher & Blackwell LLP, 1850 M Street, NW., Suite 900, Washington, DC 20036.

Synopsis: The amendment would suspend the operation of the SCE service on a temporary basis and authorize the parties to cooperate on the Grand Alliance's NCE service. The parties request expedited review.

By Order of the Federal Maritime Commission.

Dated: October 26, 2009.

Tanga S. FitzGibbon,

Assistant Secretary.

[FR Doc. E9–26133 Filed 10–29–09; 8:45 am]

BILLING CODE P

GOVERNMENT ACCOUNTABILITY OFFICE

Advisory Council on Government Auditing Standards; Notice of Meeting

The Advisory Council on Government Auditing Standards will meet Tuesday, November 17, 2009, from 8:15 a.m. to 3:30 p.m., in room 6N30 of the Government Accountability Office building, 441 G Street, NW., Washington, DC.

The Advisory Council on Government Auditing Standards will hold a meeting to discuss issues associated with potential revisions of the 2007 Revision of Government Auditing Standards, including possible revision to the independence standard and to address other issues identified by the Council. The meeting is open to the public. Members of the public will be provided an opportunity to address the Council with a brief (five minute) presentation in the afternoon.

Any interested person who plans to attend the meeting as an observer must contact Jennifer Allison, Council Administrator, 202–512–3423. A form of picture identification must be presented to the GAO Security Desk on the day of the meeting to obtain access to the GAO building. For further information, please contact Ms. Allison. Please check the Government Auditing Standards Web page (*http://www.gao.gov/govaud/ybk01.htm*) one week prior to the meeting for a final agenda.

[Pub. L. 67–13, 42 Stat. 20 (June 10, 1921)]

Dated: October 22, 2009.

James R. Dalkin,

Director, Financial Management and Assurance.

[FR Doc. E9–26065 Filed 10–29–09; 8:45 am]

BILLING CODE 1610–02–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Decision To Evaluate a Petition To Designate a Class of Employees of Hooker Electrochemical Corporation, Niagara Falls, NY, To Be Included in the Special Exposure Cohort

AGENCY: National Institute for Occupational Safety and Health (NIOSH), Department of Health and Human Services (HHS).

ACTION: Notice.

SUMMARY: HHS gives notice as required by 42 CFR 83.12(e) of a decision to evaluate a petition to designate a class of employees of Hooker Electrochemical Corporation, Niagara Falls, New York, to be included in the Special Exposure Cohort under the Energy Employees Occupational Illness Compensation Program Act of 2000. The initial proposed definition for the class being evaluated, subject to revision as warranted by the evaluation, is as follows:

Facility: Hooker Electrochemical Corporation.

Location: Niagara Falls, New York.

Job Titles and/or Job Duties: All employees who worked in any location.

Period of Employment: January 1, 1943 to December 31, 1948, and from January 1, 1949 to December 31, 1976.

FOR FURTHER INFORMATION CONTACT: Larry Elliott, Director, Office of Compensation Analysis and Support, National Institute for Occupational Safety and Health (NIOSH), 4676 Columbia Parkway, MS C–46, Cincinnati, OH 45226, Telephone 513–533–6800 (this is not a toll-free number). Information requests can also be submitted by e-mail to *OCAS@CDC.GOV.*

John Howard,

Director, National Institute for Occupational Safety and Health.

[FR Doc. E9–26161 Filed 10–29–09; 8:45 am]

BILLING CODE 4163–19–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Decision to Evaluate a Petition To Designate a Class of Workers of North American Aviation Who Worked at the Canoga Avenue Facility, Los Angeles, CA, To Be Included in the Special Exposure Cohort

AGENCY: National Institute for Occupational Safety and Health (NIOSH), Department of Health and Human Services (HHS).

ACTION: Notice.

SUMMARY: HHS gives notice as required by 42 CFR 83.12(e) of a decision to evaluate a petition to designate a class of workers of North American Aviation who worked at the Canoga Avenue Facility, Los Angeles, California, to be included in the Special Exposure Cohort under the Energy Employees Occupational Illness Compensation Program Act of 2000. The initial proposed definition for the class being evaluated, subject to revision as warranted by the evaluation, is as follows:

Facility: Canoga Avenue Facility.

Location: Los Angeles, California.

Job Titles and/or Job Duties: All workers employed by North American Aviation who worked in any areas in any job capacity.

Period of Employment: January 1, 1955 to December 31, 1960.

FOR FURTHER INFORMATION CONTACT: Larry Elliott, Director, Office of Compensation Analysis and Support, National Institute for Occupational Safety and Health (NIOSH), 4676 Columbia Parkway, MS C–46, Cincinnati, OH 45226, Telephone 513–533–6800 (this is not a toll-free number). Information requests can also be submitted by e-mail to *OCAS@CDC.GOV.*

John Howard,

Director, National Institute for Occupational Safety and Health.

[FR Doc. E9–26160 Filed 10–29–09; 8:45 am]

BILLING CODE 4163–19–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Designation of a Class of Employees for Addition to the Special Exposure Cohort

AGENCY: National Institute for Occupational Safety and Health (NIOSH), Department of Health and Human Services (HHS).

ACTION: Notice.

SUMMARY: HHS gives notice of a decision to designate a class of employees at the Norton Company, Worcester, Massachusetts, as an addition to the Special Exposure Cohort (SEC) under the Energy Employees Occupational Illness Compensation Program Act of 2000. On September 29, 2009, the Secretary of HHS designated the following class of employees as an addition to the SEC:

All AWE employees who worked at the Norton Company in Worcester, Massachusetts, from January 1, 1945 through December 31, 1957, for a number of work days aggregating at least 250 work days, occurring either solely under this employment, or in combination with work days within the parameters established for one or more other classes of employees in the Special Exposure Cohort.

This designation will become effective on October 29, 2009, unless Congress provides otherwise prior to the effective date. After this effective date, HHS will publish a notice in the **Federal Register** reporting the addition of this class to the SEC or the result of any provision by Congress regarding the decision by HHS to add the class to the SEC.

FOR FURTHER INFORMATION CONTACT: Larry Elliott, Director, Office of Compensation Analysis and Support, National Institute for Occupational Safety and Health (NIOSH), 4676 Columbia Parkway, MS C–46, Cincinnati, OH 45226, Telephone 513–533–6800 (this is not a toll-free number). Information requests can also be submitted by e-mail to *OCAS@CDC.GOV.*

John Howard,

Director, National Institute for Occupational Safety and Health.

[FR Doc. E9–26162 Filed 10–29–09; 8:45 am]

BILLING CODE 4160–17–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Designation of a Class of Employees for Addition to the Special Exposure Cohort

AGENCY: National Institute for Occupational Safety and Health (NIOSH), Department of Health and Human Services (HHS).

ACTION: Notice.

SUMMARY: HHS gives notice of a decision to designate a class of employees at the Lake Ontario Ordnance Works, Niagara Falls, New York, as an addition to the Special Exposure Cohort (SEC) under the Energy Employees Occupational Illness Compensation Program Act of 2000. On September 29, 2009, the Secretary of HHS designated the following class of employees as an addition to the SEC:

All employees of the DOE, its predecessor agencies, and their contractors and subcontractors who worked at Lake Ontario Ordnance Works in Niagara Falls, New York from January 1, 1944 through December 31, 1953, for a number of work days aggregating at least 250 work days, occurring either solely under this employment, or in combination with work days within the parameters established for one or more other classes of employees in the SEC.

This designation will become effective on October 29, 2009, unless Congress provides otherwise prior to the effective date. After this effective date, HHS will publish a notice in the **Federal Register** reporting the addition of this class to the SEC or the result of any provision by Congress regarding the decision by HHS to add the class to the SEC.

FOR FURTHER INFORMATION CONTACT: Larry Elliott, Director, Office of Compensation Analysis and Support, National Institute for Occupational Safety and Health (NIOSH), 4676 Columbia Parkway, MS C–46, Cincinnati, OH 45226, Telephone 513–533–6800 (this is not a toll-free number). Information requests can also be submitted by e-mail to *OCAS@CDC.GOV.*

John Howard,

Director, National Institute for Occupational Safety and Health.

[FR Doc. E9–26163 Filed 10–29–09; 8:45 am]

BILLING CODE 4160–17–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

[Document Identifier CMS–319, CMS–301, CMS–1957 and CMS–317]

Agency Information Collection Activities: Submission for OMB Review; Comment Request

AGENCY: Centers for Medicare & Medicaid Services.

In compliance with the requirement of section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995, the Centers for Medicare & Medicaid Services (CMS), Department of Health and Human Services, is publishing the following summary of proposed collections for public comment. Interested persons are invited to send comments regarding this burden estimate or any other aspect of this collection of information, including any of the following subjects: (1) The necessity and utility of the proposed information collection for the proper performance of the Agency's function; (2) the accuracy of the estimated burden; (3) ways to enhance the quality, utility, and clarity of the information to be collected; and (4) the use of automated collection techniques or other forms of information technology to minimize the information collection burden.

1. *Type of Information Collection Request:* Revision of the currently approved collection; *Title of Information Collection:* State Medicaid Eligibility Quality Control (MEQC) Sample Selection Lists and Supporting Regulations in 42 CFR 431.800–431.865; *Use:* State Medicaid Eligibility Quality Control (MEQC) is operated by the State Title XIX agency to monitor and improve the administration of its Medicaid system. The MEQC system is based on State reviews of Medicaid beneficiaries identified through statistically reliable statewide samples of cases selected from the eligibility files. These reviews are conducted to determine whether or not the sampled cases meet applicable State Title XIX eligibility requirements by States performing the traditional sample process. The reviews are also used to assess beneficiary liability, if any, and to determine the amounts paid to provide Medicaid services for these cases. At the beginning of each month, State agencies still performing the traditional sample are required to submit sample selection lists which identify all of the cases selected for review in the States' samples. The sample selection lists contain identifying information on Medicaid beneficiaries such as: State agency review number; beneficiary's name and address; the name of the county where beneficiary resides; Medicaid case number, etc. The submittal of the sample selection lists is necessary for regional office (RO) validation of State reviews. Without these lists, the integrity of the sampling results would be suspect and the ROs would have no data on the adequacy of the States' monthly sample draw or review completion status.; *Form Number:* CMS–319 (OMB#: 0938–0147); Frequency: Reporting—Monthly; *Affected Public:* State, Local or Tribal governments; *Number of Respondents:* 10; *Total Annual Responses:* 120; *Total Annual Hours:* 960. (For policy questions regarding this collection contact Jessica Woodard 410–786–9249. For all other issues call 410–786–1326.)

2. *Type of Information Collection Request:* Revision of a currently approved collection; *Title of Information Collection:* Certification of Medicaid Eligibility Quality Control Payment Error Rates and Supporting Regulations Contained in 42 CFR 431.816; *Use:* Under the MEQC program, States can operate the traditional MEQC sample-and-review program or States can elect to study targeted areas of eligibility or program administration that are error-prone or that will help to prevent or reduce erroneous or misspent funds. These alternative MEQC programs are called MEQC pilots. Some States operate alternative MEQC programs as part of their research and demonstration waivers under Section 1115 of the Social Security Act. The majority of States operate some form of alternative MEQC program. However, since the number of States that conduct traditional MEQC programs and alternative MEQC programs can fluctuate at any time, we have assessed the burden and costs associated with submitting the Payment Error Rate form as if all States were reporting this information.

State agencies are required to submit the Payment Error Rate form to their respective CMS Regional Offices. Regional Office staff will review these forms for completeness and will forward these forms to the Central Office for compilation of error rate charts for projected quarterly withholdings and/or fiscal disallowances. The collection of information is also necessary to implement provisions from the Children's Health Insurance Program Reauthorization Act of 2009 (CHIPRA) (Pub. L. 111–3) with regard to the Medicaid Eligibility Quality Control (MEQC) and Payment Error Rate Measurement (PERM) programs. *Form Number:* CMS–301 (OMB#: 0938–0246); *Frequency:* Reporting and Recordkeeping—Yearly; *Affected Public:* State, Local, or Tribal Governments; *Number of Respondents:* 51; *Total Annual Responses:* 102; *Total Annual Hours:* 16,446. (For policy questions regarding this collection contact Jessica Woodard 410–786–9249. For all other issues call 410–786–1326.)

3. *Type of Information Collection Request:* Reinstatement without change of a previously approved collection; *Title of Information Collection:* SSO Report of State Buy-in Problem and Supporting Regulations in 42 CFR 407.40; *Use:* Under the State Buy-In program, States enroll certain groups of needy people under the Part B Supplementary Medical Insurance (SMI) Program and pay their premiums. The purpose of the ''buy-in'' is to allow the States to provide SMI protection to certain groups of needy individuals as part of its total assistance plan. Generally, States ''buy-in'' for individuals who are categorically needy under Medicaid and meet the eligibility requirements for Medicare Part B. States can also include in their buy-in agreement those eligible for medical assistance only. The CMS–1957 is used in the resolution of beneficiary complaints regarding State buy-in. This form facilitates the coordination of efforts between the SSO, State Medicaid Agencies, and CMS in the resolution of a beneficiary's State buy-in problem.; *Form Number:* CMS–1957 (OMB#: 0938–0035); *Frequency:* Reporting—On occasion; *Affected Public:* Federal government, Individuals or Households, and State, Local, and Tribal governments; *Number of Respondents:* 5,600; *Total Annual Responses:* 5,600; *Total Annual Hours:* 1,816. (For policy questions regarding this collection contact Lucia Diaz-Robinson 410–786–0598. For all other issues call 410–786–1326.)

4. *Type of Information Collection Request:* Extension of a currently approved collection; *Title of Information Collection:* State Medicaid Eligibility Quality Control Sampling Plan and Supporting Regulations in 42 CFR 431.800–431.865; *Use:* The Medicaid Eligibility Quality Control (MEQC) System is operated by the State Title XIX agency to monitor and improve the administration of its Medicaid system. The MEQC system is based on monthly State reviews of Medicaid cases by States performing the traditional sampling process identified through statistically reliable statewide samples of cases selected from the eligibility files. These reviews are conducted to determine whether or not the sampled cases meet applicable State Title XIX eligibility requirements. The reviews are also used to assess beneficiary liability, if any, and to determine the amounts paid to provide Medicaid services for these cases.; *Form Number:* CMS–317 (OMB#: 0938–0146); *Frequency:* Recordkeeping and Reporting—Semi-annually; *Affected Public:* State, Local or Tribal governments; *Number of Respondents:* 10; *Total Annual Responses:* 20; *Total Annual Hours:* 480. (For policy questions regarding this collection contact Jessica Woodard 410–786–9249. For all other issues call 410–786–1326.)

To obtain copies of the supporting statement and any related forms for the proposed paperwork collections referenced above, access CMS Web Site address at *http://www.cms.hhs.gov/PaperworkReductionActof1995,* or E-mail your request, including your address, phone number, OMB number, and CMS document identifier, to *Paperwork@cms.hhs.gov,* or call the Reports Clearance Office on (410) 786–1326.

To be assured consideration, comments and recommendations for the proposed information collections must be received by the OMB desk officer at the address below, no later than 5 p.m. on *November 30, 2009.* OMB, Office of Information and Regulatory Affairs, *Attention:* CMS Desk Officer, *Fax Number:* (202) 395–6974, *E-mail: OIRA_submission@omb.eop.gov.*

Dated: October 23, 2009.

Michelle Shortt,

Director, Regulations Development Group, Office of Strategic Operations and Regulatory Affairs.

[FR Doc. E9–26113 Filed 10–29–09; 8:45 am]

BILLING CODE 4120–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Substance Abuse and Mental Health Services Administration

Agency Information Collection Activities: Proposed Collection; Comment Request

In compliance with Section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995 concerning opportunity for public comment on proposed collections of information, the Substance Abuse and Mental Health Services Administration (SAMHSA) will publish periodic summaries of proposed projects. To request more information on the proposed projects or to obtain a copy of the information collection plans, call the SAMHSA Reports Clearance Officer on (240) 276–1243.

Comments are invited on: (a) Whether the proposed collections of information are necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the proposed collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; and (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology.

Proposed Project: Pretesting of Substance Abuse Prevention and Treatment and Mental Health Services Communication Messages—(OMB No. 0930–0196)—Extension

As the Federal agency responsible for developing and disseminating authoritative knowledge about substance abuse prevention, addiction treatment, and mental health services and for mobilizing consumer support and increasing public understanding to overcome the stigma attached to addiction and mental illness, the Substance Abuse and Mental Health Services Administration (SAMHSA) is responsible for development and dissemination of a wide range of education and information materials for both the general public and the professional communities. This submission is for generic approval and will provide for formative and qualitative evaluation activities to (1) assess audience knowledge, attitudes, behavior and other characteristics for the planning and development of messages, communication strategies and public information programs; and (2) test these messages, strategies and program components in developmental form to assess audience comprehension, reactions and perceptions. Information obtained from testing can then be used to improve materials and strategies while revisions are still affordable and possible. The annual burden associated with these activities is summarized below.

Activity	Number of respondents	Responses/ respondent	Hours per response	Total hours
Individual In-depth Interviews:				
General Public	400	1	.75	300
Service Providers	200	1	.75	150
Focus Group Interviews:				
General Public	3,000	1	1.5	4,500
Service Providers	1,500	1	1.5	2,250
Telephone Interviews:				
General Public	335	1	.08	27
Service Providers	165	1	.08	13
Self-Administered Questionnaires:				
General Public	2,680	1	.25	670
Service Providers	1,320	1	.25	330
Gatekeeper Reviews:				
General Public	1,200	1	.50	600
Service Providers	900	1	.50	450
Total	11,700			9,290

Send comments to Summer King, SAMHSA Reports Clearance Officer, Room 7–1044, One Choke Cherry Road, Rockville, MD 20857 *and* e-mail her a copy at *summer.king@samhsa.hhs.gov.* Written comments should be received within 60 days of this notice.

Dated: October 19, 2009.

Elaine Parry,

Director, Office of Program Services.

[FR Doc. E9–26197 Filed 10–29–09; 8:45 am]

BILLING CODE 4162–20–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

[Document Identifier CMS–10184]

Agency Information Collection Activities: Proposed Collection; Comment Request

AGENCY: Centers for Medicare & Medicaid Services, HHS.

In compliance with the requirement of section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995, the Centers for Medicare & Medicaid Services (CMS) is publishing the following summary of proposed collections for public comment. Interested persons are invited to send comments regarding this burden estimate or any other aspect of this collection of information, including any of the following subjects: (1) The necessity and utility of the proposed information collection for the proper performance of the agency's functions; (2) the accuracy of the estimated burden; (3) ways to enhance the quality, utility, and clarity of the information to be collected; and (4) the use of automated collection techniques or other forms of information technology to minimize the information collection burden.

1. *Type of Information Collection Request:* Extension of a currently approved collection; *Title of Information Collection:* Eligibility Error Rate Measurement in Medicaid and the Children's Health Insurance Program; *Use:* The collection of information is necessary for CMS to produce national error rates for Medicaid and CHIP as required by Public Law 107–300, the IPIA of 2002. The collection of information is also necessary to implement provisions from the Children's Health Insurance Program Reauthorization Act of 2009 (CHIPRA) (Pub. L. 111–3) with regard to the Medicaid Eligibility Quality Control (MEQC) and Payment Error Rate Measurement (PERM) programs. The information collected from the States selected for review will be used by CMS to ensure States use a statistically sound sampling methodology, to ensure the States complete reviews on all cases sampled, and will be used by the Federal contractor to calculate State and national Medicaid and CHIP eligibility error rates. *Form Number:* CMS–10184 (OMB#: 0938–1012); *Frequency:* Reporting—Occasionally; *Affected Public:* State, Local, Tribal Governments; *Number of Respondents:* 34; *Total Annual Responses:* 53; *Total Annual Hours:* 942,764. (For policy questions regarding this collection contact Jessica Woodard at 410–786–9249. For all other issues call 410–786–1326.)

To obtain copies of the supporting statement and any related forms for the proposed paperwork collections referenced above, access CMS' Web site at *http://www.cms.hhs.gov/PaperworkReductionActof1995*, or E-mail your request, including your address, phone number, OMB number, and CMS document identifier, to *Paperwork@cms.hhs.gov*, or call the Reports Clearance Office on (410) 786–1326.

In commenting on the proposed information collections please reference the document identifier or OMB control number. To be assured consideration, comments and recommendations must be submitted in one of the following ways by *December 29, 2009:*

1. *Electronically.* You may submit your comments electronically to *http://www.regulations.gov.* Follow the instructions for ''Comment or Submission'' or ''More Search Options'' to find the information collection document(s) accepting comments.

2. *By regular mail.* You may mail written comments to the following address: CMS, Office of Strategic Operations and Regulatory Affairs, Division of Regulations Development, *Attention:* Document Identifier/OMB Control Number, Room C4–26–05, 7500 Security Boulevard, Baltimore, Maryland 21244–1850.

Dated: October 23, 2009.

Michelle Shortt,

Director, Regulations Development Group, Office of Strategic Operations and Regulatory Affairs.

[FR Doc. E9–26111 Filed 10–29–09; 8:45 am]

BILLING CODE 4120–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

[CMS–1565–N]

Medicare Program; Meeting of the Practicing Physicians Advisory Council, December 7, 2009

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

ACTION: Notice.

SUMMARY: This notice announces a quarterly meeting of the Practicing Physicians Advisory Council (the Council). The Council will meet to discuss certain proposed changes in regulations and manual instructions related to physicians' services, as identified by the Secretary of Health and Human Services. This meeting is open to the public.

DATES: *Meeting Date:* Monday, December 7, 2009, from 8:30 a.m. to 5 p.m., eastern standard time (e.s.t.).

Deadline for Registration without Oral Presentation: Thursday, December 3, 2009, 12 noon, e.s.t.

Deadline for Registration of Oral Presentations: Friday, November 20, 2009, 12 noon, e.s.t.

Deadline for Submission of Oral Remarks and Written Comments: Wednesday, November 25, 2009, 12 noon, e.s.t.

Deadline for Requesting Special Accommodations: Tuesday, December 1, 2009, 12 noon, e.s.t.

ADDRESSES: *Meeting Location:* The meeting will be held in Room 505A, in the Hubert H. Humphrey Building, 200 Independence Avenue, SW., Washington, DC 20201.

Submission of Testimony: Testimonies should be mailed to Kelly Buchanan, Designated Federal Official (DFO), Centers for Medicare & Medicaid Services, 7500 Security Boulevard, Mail stop C4–13–07, Baltimore, MD 21244–1850, or contact the DFO via e-mail at *PPAC_hhs@cms.hhs.gov*.

FOR FURTHER INFORMATION CONTACT: Kelly Buchanan, DFO, (410) 786–6132, or e-mail *PPAC_hhs@cms.hhs.gov*. News media representatives must contact the CMS Press Office, (202) 690–6145. Please refer to the CMS Advisory Committees' Information Line (1–877–449–5659 toll free), (410) 786–9379 local) or the Internet at *http://www.cms.hhs.gov/home/regsguidance.asp* for additional information and updates on committee activities.

SUPPLEMENTARY INFORMATION:

I. Background

In accordance with section 10(a) of the Federal Advisory Committee Act, this notice announces the quarterly meeting of the Practicing Physicians Advisory Council (the Council). The Secretary of Health and Human Services (the Secretary) is mandated by section 1868(a)(1) of the Social Security Act (the Act) to appoint a Practicing Physicians Advisory Council based on nominations submitted by medical organizations representing physicians. The Council meets quarterly to discuss certain proposed changes in regulations and manual instructions related to physician services, as identified by the Secretary. To the extent feasible and consistent with statutory deadlines, the Council's consultation must occur before **Federal Register** publication of the proposed changes. The Council submits an annual report on its recommendations to the Secretary and the Administrator of the Centers for Medicare & Medicaid Services (CMS) not later than December 31 of each year.

The Council consists of 15 physicians, including the Chair. Members of the Council include both participating and nonparticipating physicians, and physicians practicing in rural and underserved urban areas. At least 11 members of the Council must be physicians as described in section 1861(r)(1) of the Act; that is, State-licensed doctors of medicine or osteopathy. The remaining 4 members may include dentists, podiatrists, optometrists, and chiropractors. Members serve for overlapping 4-year terms.

Section 1868(a)(2) of the Act requires that the Council meet quarterly to discuss certain proposed changes in regulations and manual issuances that relate to physicians' services, identified by the Secretary. Section 1868(a)(3) of the Act provides for payment of expenses and per diem for Council members in the same manner as members of other advisory committees appointed by the Secretary. In addition to making these payments, the Department of Health and Human Services and CMS provide management and support services to the Council. The Secretary will appoint new members to the Council from among those candidates determined to have the expertise required to meet specific agency needs in a manner to ensure appropriate balance of the Council's membership.

The Council held its first meeting on May 11, 1992. The current members are: John E. Arradondo, M.D., MPH; Vincent J. Bufalino, M.D., Chairperson; Joseph A. Giaimo, D.O.; Pamela A. Howard, M.D.; Roger L. Jordan, O.D.; Janice A. Kirsch, M.D.; Tye J. Ouzounian, M.D.; Jeffrey A. Ross, DPM, M.D.; Jonathan E. Siff, M.D., MBA; Fredrica E. Smith, M.D.; Arthur D. Snow, Jr., M.D.; Christopher J. Standaert, M.D.; and Karen S. Williams, M.D. In addition, two new members were recently appointed by the Secretary: Chiledum A. Ahaghotu, M.D., and Richard E. Smith, M.D. New members will be sworn in at the December 7, 2009 meeting.

II. Meeting Format and Agenda

The meeting will commence with the Council's Executive Director providing a status report, and the CMS responses to the recommendations made by the Council at the August 31, 2009 meeting, as well as prior meeting recommendations. Additionally, an update will be provided on the Physician Regulatory Issues Team. In accordance with the Council charter, we are requesting assistance with the following agenda topics:

- Value-Based Purchasing for Physicians and Hospitals.
- Medicare Physician Fee Schedule—Final Rule.
- Outpatient Prospective Payment System/Ambulatory Surgical Center (OPPS/ASC) Fee Schedule—Final Rule.
- Quality Initiative Update.
- Fraud and Abuse Update.
- 10th Scope of Work Update.

For additional information and clarification on these topics, contact the DFO as provided in the **FOR FURTHER INFORMATION CONTACT** section of this notice. Individual physicians or medical organizations that represent physicians wishing to present a 5-minute oral testimony on agenda issues must register with the DFO by the date listed in the **DATES** section of this notice. Testimony is limited to agenda topics only. The number of oral testimonies may be limited by the time available. A written copy of the presenter's oral remarks must be submitted to the DFO for distribution to Council members for review before the meeting by the date listed in the **DATES** section of this notice. Physicians and medical organizations not scheduled to speak may also submit written comments to the DFO for distribution by the date listed in the **DATES** section of this notice.

III. Meeting Registration and Security Information

The meeting is open to the public, but attendance is limited to the space available. Persons wishing to attend this meeting must register by contacting the DFO at the address listed in the **ADDRESSES** section of this notice or by telephone at the number listed in the **FOR FURTHER INFORMATION CONTACT** section of this notice by the date specified in the **DATES** section of this notice.

Since this meeting will be held in a Federal Government Building, the Hubert H. Humphrey Building, Federal security measures are applicable. In planning your arrival time, we recommend allowing additional time to clear security. To gain access to the building, participants will be required to show a government-issued photo identification (for example, driver's license, or passport), and must be listed on an approved security list before persons are permitted entrance. Persons not registered in advance will not be permitted into the Hubert H. Humphrey Building and will not be permitted to attend the Council meeting.

All persons entering the building must pass through a metal detector. In addition, all items brought to the Hubert H. Humphrey Building, whether personal or for the purpose of presentation, are subject to inspection. We cannot assume responsibility for coordinating the receipt, transfer, transport, storage, set-up, safety, or timely arrival of any personal belongings or items used for the purpose of presentation.

Individuals requiring sign language interpretation or other special accommodations must contact the DFO via the contact information specified in the **FOR FURTHER INFORMATION CONTACT** section of this notice by the date listed in the **DATES** section of this notice.

Authority: (Section 1868 of the Social Security Act (42 U.S.C. 1395ee) and section 10(a) of Pub. L. 92–463 (5 U.S.C. App. 2, section 10(a)).)

Dated: October 22, 2009.

Charlene Frizzera,

Acting Administrator, Centers for Medicare & Medicaid Services.

[FR Doc. E9–26225 Filed 10–29–09; 8:45 am]

BILLING CODE 4120–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute on Drug Abuse; Notice of Closed Meetings

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of the following meetings.

The meetings will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute on Drug Abuse Special Emphasis Panel; I/START Review.

Date: November 12, 2009.

Time: 9 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6101 Executive Boulevard, Rockville, MD 20852 (Virtual Meeting).

Contact Person: Gerald L. McLaughlin, PhD, Scientific Review Administrator, Office of Extramural Affairs, National Institute on Drug Abuse, NIH, DHHS, Room 220, MSC 8401, 6101 Executive Blvd., Bethesda, MD 20892–8401, 301–402–6626, *gm145a@nih.gov.*

Name of Committee: National Institute on Drug Abuse Special Emphasis Panel; Developmental Neuroscience and Drug Abuse Treatment Translation Research.

Date: December 2, 2009.

Time: 1 p.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6101 Executive Boulevard, Rockville, MD 20852 (Telephone Conference Call).

Contact Person: Minna Liang, PhD, Scientific Review Officer, Training and Special Projects Review Branch, Office of Extramural Affairs, National Institute on Drug Abuse, NIH, 6101 Executive Blvd., Room 220, MSC 8401, Bethesda, MD 20852, 301–435–1432, *liangm@nida.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.279, Drug Abuse and Addiction Research Programs, National Institutes of Health, HHS)

Dated: October 23, 2009.

Jennifer Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. E9–26132 Filed 10–29–09; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Heart, Lung, and Blood Institute; Notice of Closed Meetings

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of the following meetings.

The meetings will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Heart, Lung, and Blood Institute Special Emphasis Panel; Conference Grants (R13's).

Date: November 19–20, 2009.

Time: 11 a.m. to 10 a.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Robert T. Su, PhD, Scientific Review Officer, Review Branch/DERA, National Heart, Lung, and Blood Institute, 6701 Rockledge Drive, Room 7202, Bethesda, MD 20892–7924, 301–435–0297, *sur@mail.nih.gov.*

Name of Committee: National Heart, Lung, and Blood Institute Special Emphasis Panel; Prematurity and Respiratory Outcomes Program.

Date: November 23, 2009.

Time: 8 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Hyatt Regency Bethesda, One Bethesda Metro Center, 7400 Wisconsin Avenue, Bethesda, MD 20814.

Contact Person: Keary A Cope, PhD, Scientific Review Officer, Office of Scientific Review, National Heart, Lung, and Blood Institute, 6701 Rockledge Drive, Room 7190, Bethesda, MD 20892–7924, (301) 435–2222, *copeka@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.233, National Center for Sleep Disorders Research; 93.837, Heart and Vascular Diseases Research; 93.838, Lung Diseases Research; 93.839, Blood Diseases and Resources Research, National Institutes of Health, HHS)

Dated: October 23, 2009.

Jennifer Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. E9–26121 Filed 10–29–09; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–5281–N–83]

Annual Performance Report and Annual Homeless Assessment Report

AGENCY: Office of the Chief Information Officer, HUD.

ACTION: Notice.

SUMMARY: The proposed information collection requirement described below has been submitted to the Office of Management and Budget (OMB) for review, as required by the Paperwork Reduction Act. The Department is soliciting public comments on the subject proposal.

Annual reports to assess the performance of individual projects, to determine project compliance with funding requirements, and to report overall program performance and outcomes to HUD-staff, other federal agencies, the Congress and the Office of Management and Budget. Annual reports to understand homeless clients and their services needs at the local level.

DATES: *Comments Due Date*: November 30, 2009.

ADDRESSES: Interested persons are invited to submit comments regarding this proposal. Comments should refer to the proposal by name and/or OMB approval Number (2506–0145) and should be sent to: HUD Desk Officer, Office of Management and Budget, New Executive Office Building, Washington, DC 20503; *fax:* 202–395–5806.

FOR FURTHER INFORMATION CONTACT: Lillian Deitzer, Reports Management Officer, QDAM, Department of Housing and Urban Development, 451 Seventh Street, SW., Washington, DC 20410; e-mail Lillian Deitzer at *Lillian_L._Deitzer@HUD.gov* or telephone (202) 402–8048. This is not a toll-free number. Copies of available documents submitted to OMB may be obtained from Ms. Deitzer.

SUPPLEMENTARY INFORMATION: This notice informs the public that the Department of Housing and Urban Development has submitted to OMB a request for approval of the Information collection described below. This notice is soliciting comments from members of the public and affecting agencies concerning the proposed collection of information to: (1) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; (2) evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information; (3) enhance the quality, utility, and clarity of the information to be collected; and (4) minimize the burden of the collection of information on those who are to respond; including through the use of appropriate automated collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

This notice also lists the following information:

Title of Proposal: Annual Performance Report and Annual Homeless Assessment Report.

OMB Approval Number: 2506–0145.

Form Numbers: HUD–40118.

Description of the Need for the Information and Its Proposed Use: Annual reports to assess the performance of individual projects, to determine project compliance with funding requirements, and to report overall program performance and outcomes to HUD-staff, other federal agencies, the Congress and the Office of Management and Budget. Annual reports to understand homeless clients and their services needs at the local level.

Frequency of Submission: Quarterly, Annually.

	Number of respondents	Annual responses	×	Hours per response	=	Burden hours
Reporting Burden	6,988	1.209		24.60		207,944

Total Estimated Burden Hours: 207,944.

Status: Revision of a currently approved collection.

Authority: Section 3507 of the Paperwork Reduction Act of 1995, 44 U.S.C. 35, as amended.

Dated: October 23, 2009.

Lillian Deitzer,

Departmental Reports Management Officer, Office of the Chief Information Officer.

[FR Doc. E9–26117 Filed 10–29–09; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–5280–N–42]

Federal Property Suitable as Facilities to Assist the Homeless

AGENCY: Office of the Assistant Secretary for Community Planning and Development, HUD.

ACTION: Notice.

SUMMARY: This Notice identifies unutilized, underutilized, excess, and surplus Federal property reviewed by HUD for suitability for possible use to assist the homeless.

FOR FURTHER INFORMATION CONTACT: Kathy Ezzell, Department of Housing and Urban Development, 451 Seventh Street, SW., Room 7266, Washington, DC 20410; telephone (202) 708–1234; TTY number for the hearing- and speech-impaired (202) 708–2565 (these telephone numbers are not toll-free), or call the toll-free Title V information line at 800–927–7588.

SUPPLEMENTARY INFORMATION: In accordance with 24 CFR part 581 and section 501 of the Stewart B. McKinney Homeless Assistance Act (42 U.S.C. 11411), as amended, HUD is publishing this Notice to identify Federal buildings and other real property that HUD has reviewed for suitability for use to assist the homeless. The properties were reviewed using information provided to HUD by Federal landholding agencies regarding unutilized and underutilized buildings and real property controlled by such agencies or by GSA regarding its inventory of excess or surplus Federal property. This Notice is also published in order to comply with the December 12, 1988 Court Order in *National Coalition for the Homeless* v. *Veterans Administration,* No. 88–2503–OG (D.D.C.).

Properties reviewed are listed in this Notice according to the following categories: Suitable/available, suitable/unavailable, suitable/to be excess, and unsuitable. The properties listed in the three suitable categories have been reviewed by the landholding agencies, and each agency has transmitted to HUD: (1) Its intention to make the property available for use to assist the homeless, (2) its intention to declare the property excess to the agency's needs, or (3) a statement of the reasons that the property cannot be declared excess or made available for use as facilities to assist the homeless.

Properties listed as suitable/available will be available exclusively for homeless use for a period of 60 days from the date of this Notice. Where property is described as for ''off-site use only'' recipients of the property will be required to relocate the building to their own site at their own expense. Homeless assistance providers interested in any such property should send a written expression of interest to HHS, addressed to Theresa Rita, Division of Property Management, Program Support Center, HHS, room 5B–17, 5600 Fishers Lane, Rockville, MD 20857; (301) 443–2265. (This is not a toll-free number.) HHS will mail to the interested provider an application packet, which will include instructions for completing the application. In order to maximize the opportunity to utilize a suitable property, providers should submit their written expressions of interest as soon as possible. For complete details concerning the processing of applications, the reader is encouraged to refer to the interim rule governing this program, 24 CFR part 581.

For properties listed as suitable/to be excess, that property may, if subsequently accepted as excess by GSA, be made available for use by the homeless in accordance with applicable law, subject to screening for other Federal use. At the appropriate time, HUD will publish the property in a Notice showing it as either suitable/available or suitable/unavailable.

For properties listed as suitable/unavailable, the landholding agency has decided that the property cannot be declared excess or made available for use to assist the homeless, and the property will not be available.

Properties listed as unsuitable will not be made available for any other purpose for 20 days from the date of this Notice. Homeless assistance providers interested in a review by HUD of the determination of unsuitability should call the toll free information line at 1–800–927–7588 for detailed instructions or write a letter to Mark Johnston at the address listed at the beginning of this Notice. Included in the request for review should be the property address (including zip code), the date of publication in the **Federal Register**, the landholding agency, and the property number.

For more information regarding particular properties identified in this Notice (*i.e.,* acreage, floor plan, existing sanitary facilities, exact street address), providers should contact the appropriate landholding agencies at the following addresses: *Energy:* Mr. Mark Price, Department of Energy, Office of Engineering & Construction Management, MA–50, 1000 Independence Ave, SW., Washington, DC 20585: (202) 586–5422; *GSA:* Mr. Gordon Creed, Acting Deputy Assistant Commissioner, General Services Administration, Office of Property Disposal, 18th & F Streets, NW., Washington, DC 20405; (202) 501–0084; *Navy:* Mrs. Mary Arndt, Acting Director, Department of the Navy, Real Estate Services, Naval Facilities Engineering Command, Washington Navy Yard, 1322 Patterson Ave., SE., Suite 1000, Washington, DC 20374–5065; (202) 685–9305; (These are not toll-free numbers).

Dated: October 22, 2009.

Mark R. Johnston,

Deputy Assistant Secretary for Special Needs.

TITLE V, FEDERAL SURPLUS PROPERTY PROGRAM FEDERAL REGISTER REPORT FOR 10/30/2009

Suitable/Available Properties

Building

Alaska

Salmonberry Qtrs.
157 Salmonberry
Bethel AK 99559
Landholding Agency: GSA
Property Number: 54200940001
Status: Excess
GSA Number: 9–U–AK–825
Comments: 2600 sq. ft., most recent use—residential

Montana

Admin Site/Warehouse
731 1st Ave, South
Glasgow MT 59230
Landholding Agency: GSA
Property Number: 54200940002
Status: Excess
GSA Number: 7–I–MT–0631
Comments: 1600 sq. ft., most recent use—office/storage

Unsuitable Properties Building

California

Border Patrol Station

Fresno CA 93722
Landholding Agency: GSA
Property Number: 54200940003
Status: Surplus
GSA Number: 9–X–CA–1677
Reasons: Extensive deterioration

Structure 363
Naval Base
San Diego CA
Landholding Agency: Navy
Property Number: 77200940001
Status: Unutilized
Reasons: Secured Area Extensive deterioration

Bldg. 43257
Marine Corps Base
Camp Pendleton CA 92055
Landholding Agency: Navy
Property Number: 77200940005
Status: Excess
Reasons: Secured Area Extensive deterioration

Hawaii

Bldgs. 62, 63, 85, 99
Naval Station
Honolulu HI 96797
Landholding Agency: Navy
Property Number: 77200940002
Status: Excess
Reasons: Secured Area

New Mexico

5 Bldgs.
Los Alamos National Lab
Los Alamos NM 87545
Landholding Agency: Energy
Property Number: 41200940001
Status: Excess
Directions: 54–0002, 54–0008, 54–0011, 54–0020, 54–0048
Reasons: Secured Area Extensive deterioration

10 Bldgs.
Los Alamos National Lab
Los Alamos NM 87545
Landholding Agency: Energy
Property Number: 41200940002
Status: Excess
Directions: 54–0153, 54–0156, 54–0224, 54–0242, 54–0281, 54–0282, 54–0289, 54–0464, 54–1051, 54–1052
Reasons: Secured Area Extensive deterioration

10 Bldgs.
Los Alamos National Lab
Los Alamos NM 87545
Landholding Agency: Energy
Property Number: 41200940003
Status: Excess
Directions: 15–0263, 16–0306, 16–0430, 16–0435, 16–0437, 18–0028, 18–0037, 18–0138, 18–0227, 18–0297
Reasons: Secured Area Within 2000 ft. of flammable or explosive material

Washington

Bldg. 171
Naval Magazine
Indian Island
Port Hadock WA 98339
Landholding Agency: Navy
Property Number: 77200940003
Status: Excess
Reasons: Secured Area Extensive deterioration

GM–1, Gold Mountain
Naval Base
Transmitter/Generator Bldg.
Kitsap WA
Landholding Agency: Navy
Property Number: 77200940004
Status: Excess
Reasons: Secured Area

[FR Doc. E9–25912 Filed 10–29–09; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–5358–N–01]

Reconsideration of Waivers Granted to and Alternative Requirements for the State of Mississippi Under Public Laws 109–148 and 109–234

AGENCY: Office of the Secretary, HUD.

ACTION: Notice of reconsidered waivers and alternative requirements.

SUMMARY: As described in the Supplementary Information section of this Notice, HUD is authorized by statute to waive statutory and regulatory requirements and specify alternative requirements for this purpose, upon the request of the State grantees. This Notice describes the statutorily required reconsideration of additional waivers and alternative requirements applicable to the Community Development Block Grant (CDBG) disaster recovery grant provided to the State of Mississippi under the subject appropriations acts.

DATES: Effective Date: November 4, 2009

FOR FURTHER INFORMATION CONTACT: Scott Davis, Director, Disaster Recovery and Special Issues Division, Office of Block Grant Assistance, Department of Housing and Urban Development, 451 Seventh Street, SW., Room 7286, Washington, DC 20410–7000, telephone number 202–708–3587. Persons with hearing or speech impairments may access this number via TTY by calling the Federal Information Relay Service at 800–877–8339. Fax inquiries may be sent to Mr. Davis at 202–401–2044. (Except for the ''800'' number, these telephone numbers are not toll-free.)

SUPPLEMENTARY INFORMATION:

Authority To Grant Waivers

The first Federal fiscal year 2006 supplemental appropriation for the Community Development Block Grant (CDBG) disaster recovery program was the Department of Defense, Emergency Supplemental Appropriations to Address Hurricanes in the Gulf of Mexico, and Pandemic Influenza Act, 2006 (Pub. L. 109–148, enacted December 30, 2005), which appropriated $11.5 billion for necessary expenses related to disaster relief, long-term recovery, and restoration of infrastructure directly related to the consequences of the covered disasters. The second supplemental appropriation was in the Emergency Supplemental Appropriations Act for Defense, the Global War on Terror, and Hurricane Recovery, 2006 (Pub. L. 109–234, enacted June 15, 2006), which appropriated $5.2 billion in CDBG funds for necessary expenses related to disaster relief, long-term recovery, and restoration of infrastructure in the most impacted and distressed areas related to the consequences of the covered disasters. Both of these supplemental appropriation acts authorized the Secretary to waive, or specify alternative requirements for, any provision of any statute or regulation that the Secretary administers in connection with the obligation by the Secretary or use by the recipient of these funds and guarantees, except for requirements related to fair housing, nondiscrimination, labor standards, and the environment (including waivers concerning lead-based paint), upon a request by the state and a finding by the Secretary that such a waiver would not be inconsistent with the overall purpose of the statute.

The Secretary finds that the following waivers and alternative requirements, as described below, are not inconsistent with the overall purpose of Title I of the Housing and Community Development Act of 1974, as amended (42 U.S.C. 5301 *et seq.*) (the 1974 Act), or the Cranston-Gonzalez National Affordable Housing Act, as amended (42 U.S.C. 12721 *et seq.*). Under the requirements of the Department of Housing and Urban Development Act, as amended (42 U.S.C. 3535(q)), regulatory waivers must be published in the **Federal Register**. The waivers and alternative requirements contained in this notice were originally published October 24, 2006, (71 FR 62372), March 6, 2007, (72 FR 10020) and October 31, 2007, (72 FR 61788). Upon a finding of good cause supported by a written request from the State of Mississippi, these waivers and alternative requirements are being retained after reconsideration.

Except as described in this and other notices applicable to these grants, statutory and regulatory provisions governing the CDBG program for States, including those at 24 CFR part 570, shall apply to the use of these funds.

Description of Changes

This Notice does not address overall benefit. The waivers related to overall benefit in Mississippi were published in several previous notices. Because the waivers are inextricably interrelated and have common alternative requirements, HUD reconsidered all of them on December 12, 2008 (73 FR 75733), at which point, the reconsideration of the first waiver was required. Additionally, in the December 12, 2008, Notice, HUD rescinded the waiver granted in paragraph 5 of the March 6, 2007, Notice (72 FR 10021), to the extent that it covers the Economic Development and Community Revitalization program. HUD continues to expect Mississippi to maintain low- and moderate-income benefit documentation for each activity providing such benefit.

Waiver Justification

In general, waivers already granted to the State of Mississippi and alternative requirements already specified for CDBG disaster recovery grant funds provided under Public Law 109–148 and Public Law 109–234 apply. The notices in which these prior waivers and alternative requirements applicable to Mississippi were published on February 13, 2006, (71 FR 7666), June 14, 2006, (71 FR 34457), October 24, 2006 (71 FR 62372), October 30, 2006; (71 FR 63337), March 6, 2007, (72 FR 10020), August 24, 2007; (72 FR 48808), October 31, 2007; (72 FR 61788), August 8, 2008 (73 FR 46312), and December 12, 2008 (73 FR 75733). These provisions provide additional flexibility in program design and implementation for the disaster recovery grants. Please note, the provisions of this Notice do not apply to funds provided under the annual CDBG program.

Low- and moderate-income household benefit for multi-unit housing projects. Upon consideration, HUD is retaining the state's waiver of 24 CFR 570.483(b)(3) so that it can fund multi-unit projects and measure benefit to low- and moderate income households in such projects in a manner more supportive of mixed income housing. Under the cited regulation, the general rule is that at least 51 percent of the residents of an assisted structure must be income eligible. However, this waiver allows a proportional units approach, in which the number of income-eligible units is proportional to the amount of assistance provided.

Therefore, the waiver and alternative requirements continue to give the State a choice. The State may measure benefit within a housing development project (1) according to the existing CDBG requirements, (2) according to the HOME program requirements at 24 CFR 92.205(d), or (3) according to the modified CDBG alternative requirements specified in this notice. The State must select and use just one method for each project. For these purposes, the term ''project'' will have the same meaning as in the HOME program at 24 CFR 92.2. Unlike the HOME program, the CDBG program does not regulate the maximum amount of assistance per unit, require unit and income reviews in the years following initial occupancy, require a specific form of subsidy layering review, or define affordability. The State is reminded, however, that CDBG does require that costs be necessary and reasonable and that the State must develop procedures and documentation to ensure that its housing investments meet this requirement. The State must also meet all civil rights and fair housing requirements.

Housing incentives to resettle in Mississippi. The State may offer disaster recovery or mitigation housing incentives to promote housing development or resettlement in particular geographic areas. These incentives have served as a valuable tool in helping the State to mitigate risk to housing and communities, thereby reducing damage and cost in future disasters. With Mississippi's request, the Department is retaining the waiver of the 1974 Act and associated regulations to the extent necessary to make this use of grant funds eligible.

Eligibility—buildings for the general conduct of government. Upon consideration, HUD is retaining the State's requested eligibility waiver to allow it to fund buildings for the general conduct of government in accordance with its Action Plan. The State can continue to assist construction, reconstruction, or rehabilitation of such buildings when the assistance meets the criteria in the Action Plan. HUD considered the State's request and agrees that it is still consistent with the overall purposes of the 1974 Act for the State to be allowed to use the grant funds under this Notice to fund critical projects involving repair of buildings for the general conduct of government that the State has selected in accordance with the method described in its Action Plan for Disaster Recovery and that the State has determined have substantial value in promoting disaster recovery.

Public benefit for certain economic development activities. For its economic development programs, the State has requested a waiver of the public benefit standards for its economic development activities. The public benefit provisions set standards for individual economic development activities (such as a single loan to a business) and for economic development activities in the annual aggregate. These dollar thresholds were set more than a decade ago and under disaster recovery conditions (which often require a larger investment to achieve a given result), can be too low and thus impede recovery by limiting the amount of assistance the grantee may provide to a critical activity. The State has made public in its Action Plan the disaster recovery needs each activity is addressing and the public benefits expected. After consideration, this Notice retains the waiver for public benefit standards for the cited activities, except that the state shall report and maintain documentation on the creation and retention of, (a) total jobs, (b) number of jobs within certain salary ranges, (c) the average amount of assistance per job and activity or program, and (d) the types of jobs. As a conforming change for the same activities or programs, HUD is also waiving 24 CFR 570.482(g) to the extent its provisions are related to public benefit.

Eligibility—Tourism. Upon reconsideration, HUD is retaining the waiver allowing support of the tourism industry. The Department understands that the support provided by Mississippi has been a useful recovery tool in a damaged regional economy that depends on tourism for many of its jobs and tax revenues. The jobs and tax revenues produced as a result of support of the tourism industry have played a valuable role in the economic revitalization of the Mississippi Gulf Coast region. The waiver will continue to permit advertising and marketing activities rather than direct assistance to tourism dependent businesses. Because the measures of long-term benefit from the proposed activities must be derived using regression analysis and other indirect means, the waiver will still cap the funds that may be used for this purpose. However, based on the state's request, that cap will increase from $5 million to $7 million. The assisted activities must continue to support tourism to the most impacted and distressed areas related to the effects of Hurricane Katrina. This waiver will now expire 2 years after the date of this notice, after which, support of the tourism industry will again be ineligible for CDBG disaster recovery funding.

Eligibility—Project-Based Rental Assistance. After reconsideration, HUD is also retaining the waiver to allow the use of project-based rental assistance (herein referred to as PBRA) to encourage owners, including nonprofit owners, of small rental properties to reestablish affordable rental housing in areas that suffered the greatest losses. The subsidy funding can be used in conjunction with components of the State's Small Rental Assistance Program to repair, rehabilitate, reconstruct, or convert small rental properties. The funding should continue to target housing for low- and moderate-income families.

A major challenge in providing affordable rental units is the difference between what tenants can afford to pay and the projected cost of operating these units. A project-based rental assistance program provides funding to landlords who rent a specified number of affordable apartments to low-income families or individuals. Assistance is tied directly to the properties so tenants can generally not move without losing their assistance. The Department encourages the state to avoid PBRA if other financing is available or if the project can reasonably be structured to achieve and maintain its target affordability without the subsidy. Therefore, HUD recommends an upfront review reflecting the perceived financial costs of a project over the life of the subsidy. Additionally, HUD recommends that the state establish written requirements for income eligibility, maximum rents, utility allowances, structure quality, and affirmative marketing of projects throughout the life of the program.

Rental programs of this type can be risky; HUD again reminds the state of the regulatory requirement for annual financial audits of its programs and of the requirements published in **Federal Register** notices on February 13, 2006 (71 FR 7666), October 30, 2006 (71 FR 63337), and August 8, 2008, (73 FR 46312), that its entire program be under the purview of an internal auditor.

Applicable Rules, Statutes, Waivers, and Alternative Requirements

1. *General note.* Except as described in this Notice, the statutory, regulatory, and notice provisions that shall apply to the use of these funds are:

a. Those governing the funds appropriated under Public Law 109–148 and Public Law 109–234 and already published in the **Federal Register**, including those in Notices 71 FR 7666, published February 13, 2006; (71 FR 7666), June 14, 2006; (71 FR 34457), October 30, 2006; (71 FR 63337), March 6, 2007; (72 FR 10020), August 24, 2007; (72 FR 48808), October 31, 2007; (72 FR 61788); August 8, 2008 (73 FR 46312); and December 12, 2008, (73 FR 75733).

b. Those governing the Community Development Block Grant program for states, including those at 42 U.S.C. 5301 et seq. and 24 CFR part 570.

2. *Low- and moderate-income benefit for multi-unit housing projects.* 24 CFR 570.483(b)(3) is waived to the extent necessary to allow the state to document low- and moderate-income benefit in a proportional units approach for multi-unit housing projects. HUD will consider assistance for a multi-unit housing project to benefit low- and moderate-income households in the following circumstances:

(a)(i) The CDBG assistance defrays the development costs of a housing project providing eligible permanent residential units that, upon completion, will be occupied by low- and moderate-income households; and

(ii) If the project is rental, the units occupied by low- and moderate-income households will be leased at affordable rents. The grantee or unit of general local government shall adopt and make public its standards for determining ''affordable rents'' for this purpose; and

(iii) The proportion of the total cost of developing the project to be borne by CDBG funds is no greater than the proportion of units in the project that will be occupied by low- and moderate-income households; or

(b) When CDBG funds defray the development costs of eligible permanent residential units, such funds shall be considered to benefit low- and moderate-income persons if the grantee follows the provisions of 24 CFR 92.205(d); or

(c) The requirements of 24 CFR 570.483(b)(3) are met.

(d) The State must select and use just one method for each project.

(e) The term ''project'' will have the same meaning as in the HOME program at 24 CFR 92.2.

(f) If the State applies option (a) or (b) above to a housing project, 24 CFR 570.483(b)(3) is waived for that project.

3. *Eligibility—buildings for the general conduct of government.* 42 U.S.C. 5305(a) is waived to the extent necessary to allow the state to use the grant funds under this Notice to assist construction, reconstruction, or rehabilitation of buildings for the general conduct of government that the state has selected in accordance with the method described in its Action Plan for Disaster Recovery and that the state has determined have substantial value in promoting disaster recovery.

4. *Eligibility—incentives to resettle in Mississippi.* 42 U.S.C. 5305(a) is waived to the extent necessary to make eligible incentives to resettle in Mississippi in accordance with the state's approved Action Plan and published program design.

5. *Public benefit standards for economic development activities.* For economic development activities designed to create or retain jobs or businesses, the public benefit standards at 42 U.S.C. 5305(e)(3) and 24 CFR 570.482(f)(1), (2), (3), (4)(i), (5), and (6) are waived, except that the grantee shall report and maintain documentation on the creation and retention of, (a) total jobs, (b) number of jobs within certain salary ranges, (c) average amount of assistance provided per job by activity or program, and (d) types of jobs. Paragraph (g) of 24 CFR 570.482 is also waived to the extent its provisions are related to public benefit.

6. *Waiver to permit some activities in support of the tourism industry.* 42 U.S.C. 5305(a) and 24 CFR 570.489(f) are waived to the extent necessary to make eligible use of no more than $7 million for assistance for the tourism industry, including promotion of a community or communities in general, provided the assisted activities are designed to support tourism to the most impacted and distressed areas, related to the effects of Hurricane Katrina. This waiver will expire 2 years after the date of this notice, after which support for the tourism industry, such as promotion of a community in general, will again be ineligible for CDBG funding.

7. *Waiver to permit project-based rental subsidies for affordable rental housing.* 42 U.S.C 5305(a) is waived to the extent necessary to make eligible the rental income subsidy assistance component of the Small Rental Assistance Program included in the State's HUD-approved Action Plan for Disaster Recovery, provided that the assisted activities are designed to ensure that CDBG funds will be invested only in proportion to the extent of anticipated need.

8. *Information collection approval note.* HUD has approval for information collection requirements in accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520) under OMB control number 2506–0165. In accordance with the Paperwork Reduction Act, HUD may not conduct or sponsor, nor is a person required to respond to, a collection of information, unless the collection displays a valid control number.

Catalog of Federal Domestic Assistance

The Catalog of Federal Domestic Assistance numbers for the disaster recovery grants under this Notice are as follows: 14.219; 14.228.

Finding of No Significant Impact

A Finding of No Significant Impact with respect to the environment has been made in accordance with HUD regulations at 24 CFR part 50, which implement section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332). The Finding of No Significant Impact is available for public inspection between 8 a.m. and 5 p.m. weekdays in the Office of the Rules Docket Clerk, Office of General Counsel, Department of Housing and Urban Development, 451 Seventh Street, SW., Room 10276, Washington, DC 20410–0500.

Dated: October 21, 2009.

Mercedes M. Márquez,

Assistant Secretary for Community Planning and Development.

[FR Doc. E9–26181 Filed 10–27–09; 4:15 pm]

BILLING CODE 4210–67–P

DEPARTMENT OF THE INTERIOR

Bureau of Indian Affairs

Renewal of Agency Information Collection for Appointed Counsel in Involuntary Indian Child Custody Proceedings in State Courts

AGENCY: Bureau of Indian Affairs, Interior.

ACTION: Notice of request for comments.

SUMMARY: The Bureau of Indian Affairs (BIA) is proposing to submit the information collection, titled ''Payment for Appointed Counsel in Involuntary Indian Child Custody Proceedings in State Courts, 25 CFR 23.13'' to the Office of Management and Budget for renewal. The information collection is currently authorized by OMB Control Number 1076–0111, which expires February 28, 2010. The information collection requires State courts that appoint counsel for an indigent Indian parent or Indian custodian in an involuntary Indian child custody proceeding to submit certain information to BIA for reimbursement when appointment of counsel is not authorized by State law.

DATES: Interested persons are invited to submit comments on or before December 29, 2009.

ADDRESSES: You may submit comments on the information collection to Sue Settles, Chief, Division of Human Services, Office of Indian Services, Bureau of Indian Affairs, Department of the Interior, 1849 C Street, NW., Mail Stop 4513, Washington, DC 20240, *facsimile:* (202) 208–5113.

FOR FURTHER INFORMATION CONTACT: You may request further information or obtain copies of the information collection request submission from Sue Settles, *telephone:* (202) 513–7621.

SUPPLEMENTARY INFORMATION:

I. Abstract

The BIA is seeking renewal of the approval for the information collection conducted under 25 CFR 23.13, implementing the Indian Child Welfare Act (25 U.S.C. 1901 *et seq.*). Approval for this collection expires February 28, 2010. The information collection allows BIA to receive written requests by State courts that appoint counsel for an indigent Indian parent or Indian custodian in an involuntary Indian child custody proceeding when appointment of counsel is not authorized by State law. No third party notification or public disclosure burden is associated with this collection. There is no change to the approved burden hours for this information collection.

II. Request for Comments

The BIA requests that you send your comments on this collection to the location listed in the **ADDRESSES** section. Your comments should address: (a) The necessity of the information collection for the proper performance of the agencies, including whether the information will have practical utility; (b) the accuracy of our estimate of the burden (hours and cost) of the collection of information, including the validity of the methodology and assumptions used; (c) ways we could enhance the quality, utility and clarity of the information to be collected; and (d) ways we could minimize the burden of the collection of the information on the respondents, such as through the use of automated collection techniques or other forms of information technology.

Please note that an agency may not sponsor or conduct, and an individual need not respond to, a collection of information unless it has a valid OMB Control Number. Approval for this collection expires February 28, 2010.

It is our policy to make all comments available to the public for review at the location listed in the **ADDRESSES** section during the hours of 9 a.m.–5 p.m., Eastern Time, Monday through Friday except for legal holidays. Before including your address, phone number, e-mail address or other personally identifiable information, be advised that your entire comment—including your personally identifiable information—may be made public at any time. While you may request that we withhold your personally identifiable information, we cannot guarantee that we will be able to do so.

III. Data

OMB Control Number: 1076–0111.

Title: Payment for Appointed Counsel in Involuntary Indian Child Custody Proceedings in State Courts, 25 CFR 23.13.

Brief Description of Collection: Submission of this information is required by State courts or individual Indians in order to receive payment for appointed counsel in involuntary Indian child custody proceedings in State courts, where appointment of counsel is not authorized by State law. Response is required to obtain a benefit.

Type of Review: Extension without change of a currently approved collection.

Respondents: State courts and individual Indians eligible for payment of attorney fees.

Number of Respondents: 4.

Total Number of Responses: Once, on occasion.

Estimated Time per Response: 2 hours for reporting and 1 hour for recordkeeping.

Estimated Total Annual Burden: 12 hours ([2 hours reporting × 4 respondents] + [1 hour recordkeeping + 4 respondents])

Dated: October 21, 2009.

Alvin Foster,

Chief Information Officer—Indian Affairs.

[FR Doc. E9–26159 Filed 10–29–09; 8:45 am]

BILLING CODE 4310–4J–P

DEPARTMENT OF THE INTERIOR

Office of the Special Trustee for American Indians

Notice and Request for Comments; Correction

AGENCY: Office of the Special Trustee for American Indians.

ACTION: Notice and request for comments; correction.

SUMMARY: In compliance with section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995, the Office of Special Trustee for American Indians announced the proposed extension of a public information collection, ''Trust Funds for Tribes and Individual Indians, 25 CFR 115,'' OMB Control No. 1035–0004, and that it is seeking comments on its provisions. The notice seeking public comments was published on October 16, 2009 at 74 FR 53292, and stated that comments must be received by November 16, 2009.

Notice of Correction: The comment period is actually open until December 16, 2009. Please use this new date as the time during which comments will be received in accordance with the other provisions of the October 16, 2009 notice.

Dated: October 21, 2009.

Linda S. Thomas,

Information Collection Clearance Officer.

[FR Doc. E9–26137 Filed 10–29–09; 8:45 am]

BILLING CODE 4310–2W–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[ID–957–1420–BJ]

Idaho: Filing of Plats of Survey

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of filing of plats of surveys.

SUMMARY: The Bureau of Land Management (BLM) has officially filed the plats of survey of the lands described below in the BLM Idaho State Office, Boise, Idaho, effective 9 a.m., on the dates specified.

FOR FURTHER INFORMATION CONTACT: Bureau of Land Management, 1387 South Vinnell Way, Boise, Idaho 83709–1657.

SUPPLEMENTARY INFORMATION: These surveys were executed at the request of the Bureau of Land Management to meet their administrative needs. The lands surveyed are:

The supplemental plat of section 16, T. 5 N., R. 11 E., Boise Meridian, Idaho, was prepared to amend certain lottings.

The supplemental plat showing of section 5, T. 9 S., R. 20 E., Boise Meridian, Idaho, was prepared to amend certain erroneous acreages as depicted on the plat accepted August 17, 1951.

The supplemental plat of sections 1, 2, 11, 12 and 14, T. 5 S., R. 4 W., Boise Meridian, Idaho, prepared to amend certain lottings.

These surveys were executed at the request of the USDA Forest Service to meet certain administrative and management purposes. The lands surveyed are:

The plat representing the dependent resurvey of a portion of the west boundary, T. 13 N., R. 27 E., Boise Meridian, Idaho, Group Number 1254, was accepted July 23, 2009.

These surveys were executed at the request of the Bureau of Indian Affairs to meet their administrative needs. The lands surveyed are:

The plat representing the dependent resurvey of a portion of the North Boundary of the Nez Perce Indian Reservation, south and west boundaries, and subdivisional lines and subdivision of sections 17, 18, 21, 22, and 35, Township 37 North, Range 1 West, Boise Meridian, Idaho, Group Number 1265, was accepted September 18, 2009. The plat representing the dependent resurvey of portions of the east boundary and subdivisional lines, and the subdivision of sections 25 and 35, and the survey of the 2008 meanders of the Blackfoot River in sections 24, 25, 26, 34, and 35, and the North Boundary of the Fort Hall Indian Reservation in sections 24, 25, 26, 34, and 35, Township 2 South, Range 36 East, of the Boise Meridian, Idaho, Group Number 1266, was accepted September 30, 2009.

The plat representing the dependent resurvey of a portion of the east boundary, a portion of the north boundary, a portion of the subdivisional lines, and the 1907 meanders of the left bank of the Blackfoot River in section 8, and the subdivision of certain sections, and the survey of the 2008–2009 meanders of the Blackfoot River in sections 3, 8, 9, and 10, and the North Boundary of the Fort Hall Indian Reservation in sections 3, 8, 9, and 10, Township 3 South, Range 36 East, Boise Meridian, Idaho, Group Number 1267, was accepted September 30, 2009.

Dated: October 1, 2009.

Stanley G. French,

Chief Cadastral Surveyor for Idaho.

[FR Doc. E9–26201 Filed 10–29–09; 8:45 am]

BILLING CODE 4310–GG–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[LLCOS05000 L1010 PH]

Notice of Public Meeting, BLM Colorado Southwest Resource Advisory Council, Correction, Cancellation of Meeting

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of public meeting; cancellation.

SUMMARY: The Bureau of Land Management (BLM) published a document in the **Federal Register** of April 3, 2009, notifying the public regarding meeting dates and locations for the BLM Colorado Southwest Resource Advisory Council (RAC). The meeting on November 6, 2009 has been cancelled.

SUPPLEMENTARY INFORMATION: The RAC meets in accordance with the Federal Land Policy and Management Act and the Federal Advisory Committee Act of 1972 (FACA), 5 U.S.C.

FOR FURTHER INFORMATION CONTACT: Barbara Sharrow, BLM Uncompahgre Field Manager, 2505 S. Townsend Ave., Montrose, CO 81401, 970–240–5300; or Erin Curtis, Public Affairs Specialist, 2815 H Rd., Grand Junction, CO 81506, 970–244–3097.

Barbara Sharrow,

Designated Federal Official.

[FR Doc. E9–26114 Filed 10–29–09; 8:45 am]

BILLING CODE P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[LLMTC 00900.L16100000.DP0000]

Notice of Public Meeting, Eastern Montana Resource Advisory Council Meeting

AGENCY: Bureau of Land Management, Interior, Montana, Billings and Miles City Field Offices.

ACTION: Notice of public meeting.

SUMMARY: In accordance with the Federal Land Policy and Management Act (FLPMA) and the Federal Advisory Committee Act of 1972 (FACA), the U.S. Department of the Interior, Bureau of Land Management (BLM) Eastern Montana Resource Advisory Council (RAC), will meet as indicated below.

DATES: The next regular meeting of the Eastern Montana Resource Advisory Council will be held on December 3, 2009 in Billings, MT. The meeting will start at 8 a.m. and adjourn at approximately 3:30 p.m. When determined, the meeting location will be announced in a news release.

FOR FURTHER INFORMATION CONTACT: Mark Jacobsen, Public Affairs Specialist, BLM Eastern Montana—Dakotas District, 111 Garryowen Road, Miles City, Montana 59301. *Telephone:* (406) 233–2831.

SUPPLEMENTARY INFORMATION: The 15-member Council advises the Secretary of the Interior through the Bureau of Land Management on a variety of planning and management issues associated with public land management in Montana. At these meetings, topics will include: Miles City and Billings Field Office manager updates, subcommittee briefings, work sessions and other issues that the council may raise. All meetings are open to the public and the public may present written comments to the Council. Each formal Council meeting will also have time allocated for hearing public comments. Depending on the number of persons wishing to comment and time available, the time for individual oral comments may be limited. Individuals who plan to attend and need special assistance, such as sign language interpretation, tour transportation or other reasonable accommodations should contact the BLM as provided above.

Dated: October 23, 2009.

M. Elaine Raper,

District Manager.

[FR Doc. E9–26190 Filed 10–29–09; 8:45 am]

BILLING CODE 4310–$$–P

DEPARTMENT OF THE INTERIOR

National Park Service

National Capital Region; Notice/Request for Public Meeting and Public Comments—the Lighting of the National Christmas Tree and the Subsequent 29 Day Event

SUMMARY: The National Park Service is seeking public comments and suggestions on the planning of the 2009 Lighting of the National Christmas Tree and the subsequent 29 day event.

SUPPLEMENTARY INFORMATION: The National Park Service is seeking public comments and suggestions on the planning of the 2009 Lighting of the National Christmas Tree and the subsequent 29 day event, which opens on December 3, 2009, on the Ellipse (President's Park), south of the White House. In order to facilitate this process the National Park Service will hold a meeting at 9:00 a.m. on November 12, 2009, in Room 234 of the National Capital Region Headquarters Building, at 1100 Ohio Drive, SW., Washington, DC (East Potomac Park). Persons who would like to comment at the meeting should notify the National Park Service by November 6, 2009, by calling the White House Visitor Center weekdays between 9 a.m., and 4 p.m., at (202) 208–1631.

In addition public comments and suggestions on the planning of the 2009 Lighting of the National Christmas Tree and the subsequent 29 day event may be submitted in writing. Written comments may be sent to the Park Manager, White House Visitor Center 1100 Ohio Drive, SW., Washington, DC 20242, and will be accepted until November 12, 2009.

DATES: The meeting will be held on November 12, 2009. Written comments will be accepted until November 12, 2009.

ADDRESSES: The meeting will be held at 9:00 a.m. on November 12, 2009, in room 234 of the National Capital Region Headquarters Building, at 1100 Ohio Drive, SW., Washington, DC (East Potomac Park). Written comments may be sent to the Park Manager, White House Visitor Center, 1100 Ohio Drive, SW., Washington, DC 20242. Due to delays in mail delivery, it is recommended that comments be provided by telefax at 202–208–1643 or by e-mail to *Scott_Tucker@nps.gov.* Comments may also be delivered by messenger to the White House Visitor Center at 1450 Pennsylvania Avenue, NW. in Washington, DC.

FOR FURTHER INFORMATION CONTACT: Scott Tucker at the White House Visitor

Center weekdays between 9 a.m., and 4 p.m., at (202) 208–1631.

Dated: October 21, 2009.

John Stanwich,

Deputy National Park Service Liaison to the White House.

[FR Doc. E9–26170 Filed 10–29–09; 8:45 am]

BILLING CODE P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

[FWS-R9-IA-2009-N235]

[96300-1671-0000-P5]

Receipt of Applications for Permit

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of receipt of applications for permit.

SUMMARY: We, the U.S. Fish and Wildlife Service, invite the public to comment on the following applications for permits to conduct certain activities with endangered species. The Endangered Species Act requires that we invite public comment on these permit applications.

DATES: Written data, comments or requests must be received by November 30, 2009.

ADDRESSES: Documents and other information submitted with these applications are available for review, subject to the requirements of the Privacy Act and Freedom of Information Act, by any party who submits a written request for a copy of such documents within 30 days of the date of publication of this notice to: U.S. Fish and Wildlife Service, Division of Management Authority, 4401 North Fairfax Drive, Room 212, Arlington, Virginia 22203; fax 703/358-2281.

FOR FURTHER INFORMATION CONTACT: Division of Management Authority, telephone 703/358-2104.

SUPPLEMENTARY INFORMATION:

Endangered Species

The public is invited to comment on the following applications for a permit to conduct certain activities with endangered species. This notice is provided pursuant to Section 10(c) of the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*). Submit your written data, comments, or requests for copies of the complete applications to the address shown in **ADDRESSES**.

Applicant: Jacksonville Zoological Society, Jacksonville, FL, PRT-072219

The applicant requests reissuance of their permit to import three giant otters (*Pteronura brasiliensis*) from the Government of Guyana for the purpose of enhancement of the survival of the species. This notification covers activities to be conducted by the applicant over a 5–year period.

Applicant: Duquesne University, Pittsburgh, PA, PRT-218242

The applicant requests an amendment to their permit to acquire from Coriell Institute of Medical Research, Camden, NJ, in interstate commerce cell line and DNA cultures from chimpanzee (*Pan troglodytes*), bonobo (*Pan paniscus*), gorilla (*Gorilla gorilla*), Bornean orangutan (*Pongo pygmaeus*), Sumatran orangutan (*Pongo abelii*), agile gibbon (*Hylobates agilis*), buff-cheeked gibbon (*Nomascus gabriellae*), white-cheeked gibbon (*Nomascus leucogenys*), pileated gibbon (*Hylobates pileatus*), siamang (*Symphalangus syndactylus*), black-handed spider monkey (*Ateles geoffroyi*), cotton-top tamarin (*Saguinus oedipus*), aye-aye (*Daubentonia madagascariensis*), brown lemur (*Eulemur fulvus*), ring-tailed lemur (*Lemur catta*), white sifaka (*Propithecus verreauxi*), and fat-tailed dwarf lemur (*Cheirogaleus medius*) for the purpose of scientific research. This notification covers activities conducted by the applicant over a 5–year period.

Applicant: Wild Cat Education & Conservation Fund, Occidental, CA, PRT-227438

The applicant requests a permit to import one male captive-born cheetah (*Acinonyx jubatus*) from DeWildt Cheetah and Wildlife Centre, DeWildt, South Africa, for the purpose of enhancement of the survival of the species.

Applicant: Institute of Greatly Endangered and Rare Species, Myrtle Beach, SC, PRT-230259

The applicant requests a permit to import one male and one female captive-born cheetah (*Acinonyx jubatus*) from DeWildt Cheetah and Wildlife Centre, DeWildt, South Africa, for the purpose of enhancement of the survival of the species.

Applicant: Michael S. Clifford, New York, NY, PRT-230659

The applicant requests a permit to import the sport-hunted trophy of one male bontebok (*Damaliscus pygargus pygargus*) culled from a captive herd maintained under the management program of the Republic of South Africa, for the purpose of enhancement of the survival of the species.

Dated: October 23, 2009

Lisa J. Lierheimer

Senior Permit Biologist, Branch of Permits, Division of Management Authority

[FR Doc. E9–26147 Filed 10–29– 09; 8:45 am]

BILLING CODE 4310–55–S

DEPARTMENT OF THE INTERIOR

Bureau of Indian Affairs

Tax Credit Bonds for Bureau of Indian Affairs-Funded Schools

AGENCY: Bureau of Indian Affairs, Interior.

ACTION: Solicitation of proposals.

SUMMARY: The Office of Facilities, Environmental, and Cultural Resources (OFECR) is soliciting applications for allocations of the $400,000,000 in Tax Credit Bonding Authority granted to the Secretary of the Interior (''Secretary'') as a result of the American Reinvestment and Recovery Act (ARRA) of 2009. This bonding authority is for the purpose of the construction, rehabilitation and repair of schools funded by the Bureau of Indian Affairs (BIA). Distribution of the $400,000,000 of tax credit bonds will be in two tranches—$200,000,000 in calendar year 2009 and $200,000,000 in calendar year 2010. This Notice also provides related guidance on the following: (1) Eligibility requirements that a project must meet to be considered for an allocation; (2) application requirements, deadlines, and forms for requests for allocations; (3) the method that the Secretary will use to make the allocations; and (4) certain interim guidance in this area.

DATES: To receive an allocation from the first $200,000,000 (''First Allocation'') of the Tax Credit Bonding Authority, an Application must be filed with the DOI on or before November 15, 2009, (''First Allocation Deadline''). To receive an allocation from the remaining allocation (''Second Allocation''), an Application must be filed with the DOI after November 16, 2009, and on or before March 15, 2010, (''Second Allocation Deadline''). To comment on the information collection contained in this notice, you must submit your comments by December 29, 2009.

ADDRESSES: You must submit your proposal and/or any comments on the information collection by mail or hand-carry to the DOI, Office of Facilities, Environmental and Cultural Resources, Attention: Bernadette Myers, 2051 Mercator Drive, Reston, Virginia 20191.

FOR FURTHER INFORMATION CONTACT: Bernadette Myers (703) 390–6655.

SUPPLEMENTARY INFORMATION:

Section 1. Purpose

This Notice solicits applications for allocations of the $400,000,000 in Tax Credit Bonding Authority granted to the Secretary as a result of the ARRA of 2009. This bonding authority is for the purpose of the construction, rehabilitation and repair of BIA-funded schools. Distribution of the $400,000,000 of tax credit bonds will be in two tranches—$200,000,000 in calendar year 2009 and $200,000,000 in calendar year 2010.

This Notice also provides related guidance on the following: (1) Eligibility requirements that a project must meet to be considered for an allocation; (2) application requirements, deadlines, and forms for requests for allocations; (3) the method that the Secretary will use to make the allocations; and (4) certain interim guidance in this area.

Section 2. Introduction

Part III—Tax Credit Bonds for Schools (''Tax-Credit Bonds''), Section 1521 Qualified School Construction Bonds of the ARRA of 2009, Public Law 111–5 (the ''Act'') is for the purpose of helping Tribal governments reduce the cost of loans or bonds for the construction, rehabilitation, and repair of schools funded by the BIA. In general, the Act allows Tribal governments to issue up to $400,000,000 in ''qualified tax bonds'' to finance a BIA funded elementary or secondary school or dormitory construction project. The bonding authorization is not an appropriation of Federal money or a loan guarantee. The Tribe will be responsible for paying their bonded obligations. The benefit to the Tribes under the bonding provision of the Act is that they can borrow money at a lower interest rate than they would have had to pay on non-tax-advantaged bonds.

Section 3. Background

Indian Affairs is responsible for providing facilities to support educational programs for eligible Indian School Equalization Program (ISEP) students. Its central, stated goal is to provide a high-quality educational environment for Native American children from kindergarten through high school.

Section 4. Application Requirements in General

Each application (''Application'') for an allocation of the Tax Credit Bonding Authority must be prepared and submitted in accordance with this section. In order for an Application to comply with this section, among other things, the Application must be prepared in substantially the form attached to this Notice as Appendix A, subject to such minor changes or variations as the DOI may approve in its discretion. This Notice, including Appendix A, may be found on the Indian Affairs Web site at *http://www.doi.gov/bia.* By submitting an Application, the applicant agrees to comply with the requirements of this Notice.

a. *Qualified issuer.* An Application must be submitted by an Indian Tribal government. Section 7701(a)(40)(A) defines an Indian Tribal government as the governing body of any Tribe, band, community, village, or group of Indians, or Alaska Natives which is determined by the IRS, in consultation with the Secretary, to exercise governmental functions. Section 2.01 of Revenue Procedure 2008–55, 2008–39 I.R.B. 768, provides that an Indian Tribal entity that appears on the most recent list published by the DOI in the **Federal Register** pursuant to the Federally Recognized Indian Tribe List Act of 1994, Public Law 103–454, 108 Stat. 4791 (''List Act''), is designated an Indian Tribal government for purposes of § 7701(a)(40). Section 2.03 of Rev. Proc. 2008–55 further provides that a Tribe that does not appear on the most recent list published by the Department of the Interior in the **Federal Register** pursuant to the requirements of the List Act nonetheless will be treated as an Indian Tribal government for purposes of § 7701(a)(40) if the Tribe has been acknowledged as a Federally recognized Indian Tribe, as stated in a letter from the DOI. An Application must identify the Indian Tribal government, including the Indian Tribal government's Federal tax identification number.

b. *Signatures.* An Application must be signed and dated by, and must include the printed name and title of, an authorized official of the Indian Tribal government and must be supported by a Tribal resolution indicating the Tribe's intent to apply for an allocation. For purposes of this Notice, the term ''authorized official of the Indian Tribal government'' means an officer, board member, employee, or other official of the Indian Tribal government who is duly authorized to execute legal documents on behalf of the Indian Tribal government in connection with incurring debt of the Indian Tribal government (*e.g.,* a Tribal chairperson, chief executive officer, or chief financial officer).

c. *Contact person.* An Application must designate one or more persons with knowledge of the project that the qualified issuer duly authorizes to discuss with Indian Affairs any information specifically relating to the Application. The designation must include the designee's name, title, telephone number, fax number, and mailing address.

d. *Addresses.* An Application must be submitted by hard copy in duplicate accompanied by a copy of the Application in electronic format on compact disc (''CD'') sent by mail to the address listed in the **ADDRESSES** section of this Notice.

e. *Due date.* To receive an allocation from the first $200,000,000 (''First Allocation'') of the Tax Credit Bonding Authority, an Application must be filed with the DOI on or before the Application deadline of November 15, 2009, (''First Allocation Deadline''). To receive an allocation from the remaining allocation (''Second Allocation''), an Application must be filed with the DOI after November 16, 2009, and on or before March 15, 2010, (''Second Allocation Deadline''). (*See* **DATES** section of this Notice). Should not all the Authority be granted in the two allocations, the Secretary will consider a third allocation period. *See* section 7 for further discussion of the two allocations.

f. *Project description.* Each Application must contain the information required by this subsection.

(i) *Qualified project.* Each Application must describe in reasonable detail the project to be financed with the tax-credit bonds. The Application must indicate the expected date that the acquisition and construction of the project will commence and the expected date that the project will be placed in service. The Secretary will only allocate bonding authority for projects that comply with building codes and construction requirements required by Indian Affairs for all Bureau-funded education facility construction. Further, the Secretary will only approve bonding allocation for projects that were developed using Indian Affairs education specifications, space criteria allowances, and enrollment projection methodology, and which comply with current statutory or regulatory requirements regarding school grade structure, curriculum requirements, and educational standards.

(ii) *Location of project.* The Application must include a certification that the project's location is within the Indian Tribal government's reservation.

(iii) *Regulatory approvals.* The Application must state whether all necessary Federal, State, and local regulatory approvals for the project have been obtained and, if those approvals have not yet been obtained, the Application must describe the Indian Tribal government's plan for obtaining them and the timeframe during which the Indian Tribal government expects to receive them.

g. *Plan of financing.* The Application must contain: (1) A reasonably detailed description of the plan of financing for the project, including all reasonably expected sources (*e.g.,* a public offering through a named underwriter or a private placement to a named institution) and uses of financing, including financing from the tax-credit bonds and from other sources; (2) the status of all financing, including the name and addresses of all entities expected to provide any financing; (3) the anticipated date of issuance of the tax-credit bonds and any expected purchasers of the tax-credit bonds; (4) the sources of security and repayment for the tax-credit bonds; (5) the aggregate face amount of tax-credit bonds expected to be issued for the project; and (6) the issuer's reasonably expected schedule for spending proceeds of the tax-credit bonds. If the Indian Tribal government intends to use the proceeds of tax-credit bonds to reimburse amounts paid with respect to a qualified project, the Application must demonstrate compliance with all statutory IRS tax requirements and regulations.

h. *Dollar amount of allocation requested.* The Application must specify the dollar amount of tax-credit bonds requested for the project.

i. *Statement of readiness to issue.* An Application for an allocation of the tax credit bonding authority from the First or Second Allocation must contain the statement that the issuer reasonably expects to issue any tax-credit bonds, pursuant to the requested allocation, within six months of authorization.

Section 5. Required Declarations in Application

Each application submitted under this Notice must include the following declaration signed and dated by an authorized official of the Indian Tribal government:

> Under penalties of perjury, I declare that I have examined this document and, to the best of my knowledge and belief, all of the facts contained herein are true, correct, and complete.

Section 6. Consent to Disclosure Allocation

In order for the Secretary or Indian Affairs to disclose identifying information with respect to applicants awarded an allocation, the Secretary and Indian Affairs requests that each applicant submit with the Application a declaration consenting to the Secretary's or Indian Affairs' disclosure of the name of the issuer, the type and location of the project that is the subject of the Application, and the amount of the tax credit bond allocation awarded to that Applicant if the Applicant receives an allocation. Appendix B.

Section 7. Annual Bonding Authority Limit and Methodology

a. First Allocation

The Tax Credit Bonding Authority under § 7871(f) will be allocated in at least two tranches. The first $200,000,000 will be allocated in accordance with this section for qualified projects for which Applications meeting the requirements of this Notice have been filed with the Secretary or Indian Affairs on or before the First Allocation Deadline. If the total amount of allocations requested in all applications received on or before the First Allocation Deadline does not exceed $200,000,000, then each qualified project will be allocated the amount of allocation requested. If the total amount of allocations requested in all applications received on or before the First Allocation Deadline exceeds $200,000,000, then each qualified project will be allocated a reduced pro rata such that the total amount allocated as part of the First Allocation does not exceed $200,000,000. Applicants receiving a reduced allocation may submit an application requesting the remainder of the allocation on or before the Second Allocation Deadline.

b. Second Allocation

(1) The Second Allocation will allocate the second $200,000,000. The Second Allocation will be allocated in accordance with this section for qualified projects for which Applications meeting the requirements of this Notice have been filed with the Secretary or Indian Affairs on or before the Second Allocation Deadline set forth in this Notice. If the total amount of allocations requested in all applications received on or before the Second Allocation Deadline does not exceed the Second Allocation Amount, then each qualified project will be allocated the amount requested. If the total amount of allocations requested in all applications received on or before the Second Allocation Deadline exceeds $200,000,000, then each qualified project will be allocated a reduced pro rata such that the total amount allocated as part of the Second Allocation does not exceed $200,000,000. Any allocation remaining from the Second Allocation, or any forfeited allocation, may be available as part of an allocation process to be announced by the Secretary or Indian Affairs at some future date.

(2) Applicants for any subsequent allocation other than the First Allocation must include a description of the project, or any related project, for which a prior allocation was made, as well as the name of the applicant that received the allocation. For this purpose, related projects include facilities that are owned by the same Indian Tribal government, a political subdivision of the Indian Tribal government, or an entity controlled by the Indian Tribal government, which are: (i) Located at or near the same site; and (ii) are integrated, interconnected, or directly or indirectly dependent on each other, based on all the facts and circumstances.

c. On Behalf of Issuers

(1) An Indian Tribal government that receives an allocation may designate an ''on behalf of issuer,'' so long as the Tribal government complies with all applicable statutory tax requirements and regulations.

(2) An Indian Tribal government that receives an allocation may assign the allocation to a pool bond issuer who is otherwise an Indian Tribal government for the purpose of issuing tax-credit bonds the proceeds of which will be loaned to the Indian Tribal government who received the allocation. Pooled tax-credit bonds will be subject to all applicable statutory tax requirements and regulations.

(3) The proceeds of any bonds issued by an ''on behalf of'' issuer or a pool issuer will be treated as if they were proceeds of bonds issued by the Indian Tribal government that received the allocation.

d. Forfeiture of Allocation

If bonds are not in place within six months of authorization, any or all of the allocation received by an issuer pursuant to the First and Second Allocation, then such allocation shall be considered forfeited. Any allocation amounts forfeited may be available for allocation by the Secretary as part of an allocation process to be announced by the Secretary at some future date. Issuers must notify the Secretary or Indian Affairs in writing at least 30 days before the expiration of the period during which bonds may be issued pursuant to an allocation if they do not intend to issue bonds pursuant to such allocation. Failure to comply with requirements set forth in Section 4–f(i) of this Notice will result in the loss of all Indian Affairs funding support for the functional facilities operations and maintenance of the project.

Section 8. Drafting Information

The principal authors of this Notice are John N. Rever, Director, and Bernadette Myers, Management Analyst, OFECR. Other Department of the Interior (DOI) personnel also participated in its development.

Section 9. Paperwork Reduction Act

The information collection requirements contained in this notice have been approved by the Office of Management and Budget (OMB) under an emergency request pursuant to 44 U.S.C. 3504(h). The OMB control number is 1076–0173. The authorization expires on April 30, 2010.

a. Abstract

This information collection allows the BIA to receive written applications for allocations of the $400,000,000 in Tax Credit Bonding Authority granted to the Secretary as a result of the ARRA of 2009. This bonding authority is for the purpose of the construction, rehabilitation and repair of BIA-funded schools. The information collection allows BIA to determine whether the project is eligible to be considered for an allocation. No third party notification or public disclosure burden is associated with this collection.

b. Request for Comments

If you would like to comment on this information collection, please send your comments to the location listed in the **ADDRESSES** section. Your comments should address: (a) The necessity of the information collection for the proper performance of the agencies, including whether the information will have practical utility; (b) the accuracy of our estimate of the burden (hours and cost) of the collection of information, including the validity of the methodology and assumptions used; (c) ways we could enhance the quality, utility and clarity of the information to be collected; and (d) ways we could minimize the burden of the collection of the information on the respondents, such as through the use of automated collection techniques or other forms of information technology.

Please note that an agency may not sponsor or conduct and an individual need not respond to a collection of information unless it has a valid OMB Control Number.

It is our policy to make all comments available to the public for review at the location listed in the **ADDRESSES** section during the hours of 9 a.m.–5 p.m., Eastern Time, Monday through Friday except for legal holidays. Before including your address, telephone number, e-mail address or other personally identifiable information, be advised that your entire comment—including your personally identifiable information—may be made public at any time. While you may request that we withhold your personally identifiable information, we cannot guarantee that we will be able to do so.

c. Data

OMB Control Number: 1076–0173.

Title: Tax Credit Bonds for Bureau of Indian Affairs-Funded Schools.

Brief Description of Collection: Submission of this information is required to apply for allocations of the $400,000,000 in Tax Credit Bonding Authority granted to the Secretary as a result of the ARRA of 2009. This bonding authority is for the purpose of the construction, rehabilitation and repair of BIA-funded schools. The information collection allows BIA to determine whether the project is eligible to be considered for an allocation. No third party notification or public disclosure burden is associated with this collection. Response is required to obtain a benefit.

Type of Review: New collection.

Respondents: Indian Tribal governments.

Number of Respondents: 30.

Total Number of Responses: Once, on occasion.

Estimated Time per Response: 40 hours.

Estimated Total Annual Burden: 1,200 hours.

Dated: October 26, 2009.

Larry Echo Hawk,

Assistant Secretary—Indian Affairs.

Appendix A

Application for Allocation of Tax-Credit Bonds for BIA-Funded Schools

Department of the Interior, Office of Facilities, Environmental and Cultural Resources, Attention: Bernadette Myers, 2051 Mercator Drive, Reston, Virginia 20191.

Dear Madam: The following constitutes the application (''Application'') of (Name) (the ''Applicant'') for allocation of tax-credit bonds pursuant to Title I, § 1521 of the American Recovery and Reinvestment Act to finance the project described below. (If a single Application is used to request tax-credit bonds for more than one project, then all of the required information in the Application must be provided separately for each project.)

1. Name of Applicant/Issuer __________
Street Address __________
City __________
State __________
Zip __________
Telephone Number __________
Fax Number __________
EIN __________

2. Status of Issuer—(Select as appropriate)
The Applicant/Issuer is a ''qualified issuer'' under § 7871(f) because it is—
(i) an Indian tribal entity that appears on the most recent list published by the Department of Interior in the Federal Register pursuant to the Federally Recognized Indian Tribe List Act of 1994, Pub. L. 103–454, 108 Stat. 4791 (''List''), as demonstrated by the attached documents included as Exhibit A.
(ii) an Indian tribal government which is acknowledged as a federally recognized Indian tribe, as stated in a letter from the Department of the Interior, as demonstrated by the attached documents included as Exhibit A.

3. Name of Project __________

4. Detailed Description of the Project. A reasonably detailed description of the facility to be financed (the ''Project'') is set forth below or in attached Exhibit B.

____
____
____

If the Project is a joint Project, please describe in detail the other owners of the project and the applicant's ownership interest in the project.

5. Construction Commencement Date and Placed in Service Date. The Applicant begun or expects to begin the construction, installation and equipping of the Project on __________. The Applicant expects that the Project will be placed into service on or before __________.

6. Pool Issuances. Does the Applicant expect to have the tax-credit bonds issued by a pool issuer or an ''on behalf of issuer''?

____

If the answer above is ''yes,'' please describe the pool issuer or on behalf of issuer and provide a statement that the pool issuer is an Indian tribal government or that the ''on behalf of issuer'' meets the requirements to be such an issuer under the rules applicable to bonds in accordance with current IRS regulations.

____
____
____

7. Location of the Project:
Project address or physical location (do not include postal box numbers or mailing address)

____
City __________
State __________
Zip __________
Reservation where Project will be located:

____

Include in the attached Exhibit C a certification that the Project will be located on the Applicant's reservation. If the tax-credit bonds will be issued for a joint project please include in attached Exhibit C a certification that the Project will be located on a reservation of at least one of the Indian tribal governments receiving an allocation with respect to such Project.

8. Individual to contact for more information about the Project:
Individual Name ____________
Company Name ____________
Street Address ____________
City ____________
State ____________
Zip ____________
Telephone Number ____________
Fax Number ____________
Email Address ____________

9. Regulatory Approvals. Identify each regulatory body, the action that must be taken, status of any pending action, and the remaining timeframe required to obtain each required approval. The plan of the Applicant for obtaining such approvals is as follows (or attach an Exhibit):

____
____
____

10. Plan of Financing. Include a reasonably detailed description of the plan of financing for the Project, including all reasonably expected sources and uses of financing and other funds, the status of such financing, the anticipated date of bond issuance, the sources of security and repayment for the bonds, the aggregate face amount of bonds expected to be issued for the Project, and the issuer's reasonably expected schedule for expending the proceeds of the tax-credit bonds. Attached as Exhibit D is a plan of financing for the Project.

11. Statement of Readiness.
a. Application from the First Allocation. Include in Exhibit E a statement signed under penalties of perjury that the Issuer reasonably expects to issue bonds pursuant to the requested allocation within six months of the authorization.
b. Application from the Second Allocation. Include in Exhibit E a statement signed under penalties of perjury that the Issuer reasonably expects to issue bonds pursuant to the requested allocation within six months of the authorization.

12. Dollar Amount of Allocation Requested for the Project. To finance the Project, the Applicant hereby requests a tax-credit bond allocation in the amount of $ ________.

13. Prior Allocations for the Project. (If the Project or any Related Project (as defined in section 7.b.(2) of this Notice) previously received a tax-credit bond allocation, then this paragraph must include a statement to that effect.) [If applicable, include the following statement: On (Insert date), the Project previously received a tax-credit bond allocation in the amount of $ ________. A copy of the Indian Affairs allocation letter for that allocation is attached.]

14. Assignment of allocations to another issuer. If the applicant expects to assign its allocation to another qualified issuer of tax-credit bonds as authority for the tax-credit bond issuer to issue bonds for the project on behalf of the applicant, the applicant should provide the following statement:

The Applicant expects to assign the requested allocation for tax-credit bonds to a qualified issuer of tax-credit bonds as authority for the tax-credit bond issuer to issue bonds for the project on behalf of the Applicant. Applicant agrees to obtain a written commitment from the assignee tax-credit bond issuer that it is a qualified issuer of tax-credit bonds and that it will issue tax-credit bonds for the project within the time frame specified in the Application for the Applicant's bonds.

15. Penalty of Perjury Statement and Signatures.

I hereby certify that I am an authorized officer or official of the Applicant, that I am duly authorized to execute legal documents on behalf of the Applicant in connection with incurring debt, and that I am duly authorized to execute legal documents on behalf of the Applicant in making this Application. Under penalties of perjury, I declare that (i) I have knowledge of the relevant facts and circumstances relating to this Application and the Project(s), (ii) I have examined this Application, and (iii) to the best of my knowledge and belief, all of the facts contained in this Application are true, correct and complete.

By: ____________
Name: ____________
Title: ____________
Date: ____________

Attach the following Exhibits:

Exhibit A

Documents Regarding Issuer Status as an Indian Tribal Government (Response to Question 2 of the Application)

Exhibit B

Description of the Project (Response to Question 4 of the Application)

Exhibit C

Project Location on Indian Tribal Government Reservation (Response to Question 7 of the Application)

Exhibit D

Plan of Financing (Response to Question 10 of the Application)

Exhibit E

Statement of Readiness to Issue (Response to Question 11 of the Application)

I hereby certify that I am an authorized officer or official of the Applicant, that I am duly authorized to execute legal documents on behalf of the Applicant in connection with incurring debt, and that I am duly authorized to execute legal documents on behalf of the Applicant in making this Application. Under penalties of perjury, I declare that the Applicant reasonably expects that bonds issued pursuant to the tax-credit bond allocation to be received will be issued within six months of authorization.

By: ____________
Name: ____________
Title: ____________
Date: ____________

Appendix B

Consent to Public Disclosure of Certain Tax-Credit Bond Application Information

In the event that the Application of [________________] (the "Applicant") for an allocation of authority to issue Tax Credit Bonds to be used for the purpose of the construction, rehabilitation, and repair of schools funded by the Bureau of Indian Affairs ("Tax-Credit Bonds") is approved, the undersigned authorized representative of the Applicant hereby consents to the disclosure by Department of the Interior through publication of a Notice or a press release of the name of Applicant (issuer), the type and location of the facility that is the subject of the Application, and the amount of the tax-credit bond allocation for such facility. The undersigned understands that this information might be published, broadcast, discussed or otherwise disseminated in the public record.

This authorization shall become effective upon the execution hereof.

I certify that I have the authority to execute this consent to disclose on behalf of the Applicant named below.

Date: ____________
Signature: ____________
Print name: ____________
Title: ____________
Name of Applicant: ____________
Applicant's Mailing Address: ____________
____

[FR Doc. E9–26302 Filed 10–29–09; 8:45 am]

BILLING CODE 4310–4M–P

DEPARTMENT OF JUSTICE

Notice of Lodging of Consent Decree Under the Comprehensive Environmental Response, Compensation and Liability Act

Notice is hereby given that on October 26, 2009, a proposed Settlement Agreement in *In re Hercules Chemical Company, Inc.,* Case No. 08–27822–MS, was lodged with the United States Bankruptcy Court for the District of New Jersey.

In this action, the United States filed a proof of claim seeking reimbursement for response and natural resource damage assessment costs from the Debtor under the Comprehensive Environmental Response, Compensation, and Liability Act, 42 U.S.C. 9601, *et seq.,* with respect to the Diamond Alkali Superfund Site (the Passaic River Matter) in Newark, NJ. The Settlement Agreement provides that Hercules will provide the United States a general unsecured claim of $200,000.

The Department of Justice will receive for a period of thirty (30) days from the date of this publication comments relating to the Settlement Agreement. Comments should be addressed to the Assistant Attorney General, Environment and Natural Resources Division, and either e-mailed to *pubcomment-ees.enrd@usdoj.gov* or mailed to P.O. Box 7611, U.S. Department of Justice, Washington, DC 20044–7611, and should refer to *In re*

Hercules Chemical Company, Inc., D.J. Ref. 90–11–3–07683/7.

During the public comment period, the Settlement Agreement, may also be examined on the following Department of Justice Web site, to *http://www.usdoj.gov/enrd/Consent_Decrees.html.* A copy of the Consent Decree may also be obtained by mail from the Consent Decree Library, P.O. Box 7611, U.S. Department of Justice, Washington, DC 20044–7611 or by faxing or e-mailing a request to Tonia Fleetwood (*tonia.fleetwood@usdoj.gov*), fax no. (202) 514–0097, phone confirmation number (202) 514–1547. In requesting a copy from the Consent Decree Library, please enclose a check in the amount of $4.00 (25 cents per page reproduction costs of the Settlement Agreement) payable to the U.S. Treasury or, if by e-mail or fax, forward a check in that amount to the Consent Decree Library at the stated address.

Maureen Katz,

Assistant Chief, Environmental Enforcement Section, Environment and Natural Resources Division.

[FR Doc. E9–26156 Filed 10–29–09; 8:45 am]

BILLING CODE 4410–15–P

DEPARTMENT OF LABOR

Office of the Secretary

Submission for OMB Review: Comment Request

October 26, 2009.

The Department of Labor (DOL) hereby announces the submission of the following public information collection request (ICR) to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995 (Pub. L. 104–13, 44 U.S.C. chapter 35). A copy of this ICR, with applicable supporting documentation; including, among other things, a description of the likely respondents, proposed frequency of response, and estimated total burden may be obtained from the RegInfo.gov Web site at *http://www.reginfo.gov/public/do/PRAMain* or by contacting Darrin King on 202–693–4129 (this is not a toll-free number)/*e-mail: DOL_PRA_PUBLIC@dol.gov.*

Interested parties are encouraged to send comments to the Office of Information and Regulatory Affairs, *Attn:* OMB Desk Officer for the Department of Labor—Occupational Safety and Health Administration (OSHA), Office of Management and Budget, Room 10235, Washington, DC 20503, *Telephone:* 202–395–7316/*Fax:* 202–395–5806 (these are not toll-free numbers), E-mail: *OIRA_submission@omb.eop.gov* within 30 days from the date of this publication in the **Federal Register**. In order to ensure the appropriate consideration, comments should reference the OMB Control Number (*see* below).

The OMB is particularly interested in comments which:

- Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;
- Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
- Enhance the quality, utility, and clarity of the information to be collected; and
- Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.,* permitting electronic submission of responses.

Agency: Occupational Safety and Health Administration.

Type of Review: Extension without change of a previously approved collection.

Title of Collection: Hazard Communication (29 CFR parts 1910.1200, 1915.1200, 1917.28, 1918.90, 1926.59 and 1928.21).

OMB Control Number: 1218–0072.

Affected Public: Business or other for-profits.

Estimated Number of Respondents: 2,880,308.

Estimated Total Annual Burden Hours: 10,375,704.

Estimated Total Annual Costs Burden (excludes hourly wage costs): $1,750,460.

Description: The standard requires all employers to establish hazard communications programs, to transmit information on the hazards of chemicals to their employees by means of container labels, material safety data sheets and training programs. This action will reduce the incidence of chemical related illness and injury in the workplace. For additional information, see the related 60-day preclearance notice published in the **Federal Register** at Vol. 74 FR 44876 on August 31, 2009. PRA documentation prepared in association with the preclearance notice is available on *http://www.regulations.gov* under docket number OSHA–2009–0014.

Darrin A. King,

Departmental Clearance Officer.

[FR Doc. E9–26180 Filed 10–29–09; 8:45 am]

BILLING CODE 4510–26–P

DEPARTMENT OF LABOR

Office of the Secretary

Submission for OMB Review: Comment Request

October 27, 2009.

The Department of Labor (DOL) hereby announces the submission of the following public information collection request (ICR) to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995 (Pub. L. 104–13, 44 U.S.C. chapter 35). A copy of this ICR, with applicable supporting documentation; including, among other things, a description of the likely respondents, proposed frequency of response, and estimated total burden may be obtained from the RegInfo.gov Web site at *http://www.reginfo.gov/public/do/PRAMain* or by contacting Darrin King on 202–693–4129 (this is not a toll-free number)/e-mail: *DOL_PRA_PUBLIC@dol.gov.*

Interested parties are encouraged to send comments to the Office of Information and Regulatory Affairs, *Attn:* OMB Desk Officer for the Department of Labor—Occupational Safety and Health Administration (OSHA), Office of Management and Budget, Room 10235, Washington, DC 20503, *Telephone:* 202–395–7316/*Fax:* 202–395–5806 (these are not toll-free numbers), *E-mail: OIRA_submission@omb.eop.gov* within 30 days from the date of this publication in the **Federal Register**. In order to ensure the appropriate consideration, comments should reference the OMB Control Number (*see* below).

The OMB is particularly interested in comments which:

- Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;
- Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
- Enhance the quality, utility, and clarity of the information to be collected; and

• Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

Agency: Occupational Safety and Health Administration.

Type of Review: Extension without change of a previously approved collection.

Title of Collection: Chromium (VI) Standards for General Industry (29 CFR 1910.1026), Shipyard Employment (29 CFR 1915.1026), and Construction (29 CFR 1926.1126).

OMB Control Number: 1218–0252.

Affected Public: Business or other for-profits.

Estimated Number of Respondents: 78,126.

Estimated Total Annual Burden Hours: 725,319.

Estimated Total Annual Costs Burden (excludes hourly wage costs): $47,751,607.

Description: The standard requires employers to monitor worker exposure to Chromium (VI), to provide medical surveillance, and to establish and maintain accurate records of employee exposure to Chromium and employee medical records. These records will be used by employers, workers, physicians, and the Government to ensure that workers are not being harmed by exposure to Chromium. For additional information, see the related 60-day preclearance notice published in the **Federal Register** at Vol. 74 FR 29517 on June 22, 2009. PRA documentation prepared in association with the preclearance notice is available on *http://www.regulations.gov* under docket number OSHA–2009–0015.

Darrin A. King,

Departmental Clearance Officer.

[FR Doc. E9–26187 Filed 10–29–09; 8:45 am]

BILLING CODE 4510–26–P

DEPARTMENT OF LABOR

Employment and Training Administration

Labor Surplus Area Classification Under Executive Orders 12073 and 10582

AGENCY: Employment and Training Administration, Labor.

ACTION: Notice

SUMMARY: The purpose of this notice is to announce the annual list of labor surplus areas for Fiscal Year (FY) 2010.

DATES: *Effective Date:* The annual list of labor surplus areas is effective October 1, 2009, for all States, the District of Columbia, and Puerto Rico.

FOR FURTHER INFORMATION CONTACT: Samuel Wright, Office of Workforce Investment, Employment and Training Administration, 200 Constitution Avenue, NW., Room S–4231, Washington, DC 20210. *Telephone:* (202) 693–2870 (This is not a toll-free number).

SUPPLEMENTARY INFORMATION: The Department of Labor's regulations implementing Executive Orders 12073 and 10582 are set forth at 20 CFR Part 654, Subparts A and B. These regulations require the Employment and Training Administration (ETA) to classify jurisdictions as labor surplus areas pursuant to the criteria specified in the regulations and to publish annually a list of labor surplus areas. Pursuant to those regulations, ETA is hereby publishing the annual list of labor surplus areas.

In addition, the regulations provide exceptional circumstance criteria for classifying labor surplus areas when catastrophic events, such as natural disasters, plant closings, and contract cancellations are expected to have a long-term impact on labor market area conditions, discounting temporary or seasonal factors.

Eligible Labor Surplus Areas

A Labor Surplus Area (LSA) is a civil jurisdiction that has a civilian average annual unemployment rate during the previous two calendar years of 20 percent or more above the average annual civilian unemployment rate for all States during the same 24-month reference period. Only official unemployment estimates provided to ETA by the Bureau of Labor Statistics are used in making these classifications. The average unemployment rate for all States includes data for the Commonwealth of Puerto Rico. The basic LSA classification criteria include a ''floor unemployment rate'' (6.0%) and a ''ceiling unemployment rate'' (10.0%).

Civil jurisdictions are defined as follows:

(a) A city of at least 25,000 population on the basis of the most recently available estimates from the Bureau of the Census; or

(b) A town or township in the States of Michigan, New Jersey, New York, or Pennsylvania of 25,000 or more population and which possess powers and functions similar to those of cities; or

(c) A county, except those counties which contain any type of civil jurisdictions defined in A or B above; or

(d) A ''balance of county'' consisting of a county less any component cities and townships identified in paragraphs A or B above; or

(e) A county equivalent which is a town in the States of Connecticut, Massachusetts, and Rhode Island, or a municipio in the Commonwealth of Puerto Rico.

Procedures for Classifying Labor Surplus Areas

The Department of Labor (DOL) issues the labor surplus area list on a fiscal year basis. The list becomes effective each October 1 and remains in effect through the following September 30. The reference period used in preparing the current list was January 2007 through December 2008. The national average unemployment rate during this period was 5.3 percent. Twenty percent higher than the national unemployment rate of 5.3 percent is a qualifying rate of 6.3 percent. Therefore, areas included on the FY 2010 labor surplus area list had an average unemployment rate of 6.3 percent or above during the reference period. This year the balance of county areas will only be listed were the county did not meet the unemployment qualifier as a labor surplus area but the balance of county did. A second listing would be unnecessarily redundant and potentially confusing. Several areas not on this labor surplus list have current unemployment rates that are substantially higher than the labor surplus qualifier of 6.3 percent. Most of these areas experienced unemployment rates that were considerably lower than the labor surplus qualifier of 6.3 percent for 2007 and the first half of 2008. The unemployment rates for most of these areas did not become significantly higher than 6.3 percent until after the third quarter of 2008 causing the unemployment rate for the reference period to be lower than 6.3 percent. The FY 2010 labor surplus area list can be accessed at: *http://www.doleta.gov/programs/lsa.cfm.*

Petition for Exceptional Circumstance Consideration

The classification procedures also provide for the designation of labor surplus areas under exceptional circumstance criteria. These procedures permit the regular classification criteria to be waived when an area experiences a significant increase in unemployment which is not temporary or seasonal and which was not reflected in the data for the 2-year reference period. Under the program's exceptional circumstance procedures, labor surplus area classifications can be made for civil jurisdictions, Metropolitan Statistical Areas or Primary Metropolitan Statistical Areas, as defined by the Office of Management and Budget. In order for an area to be classified as a labor surplus area under the exceptional circumstance criteria, the State workforce agency must submit a petition requesting such classification to the Department of Labor's ETA. The current criteria for an exceptional circumstance classification are: an area's unemployment rate of at least 6.3 percent for each of the three most recent months; a projected unemployment rate of at least 6.3 percent for each of the next 12 months; and documentation that the exceptional circumstance event has already occurred. The State workforce agency may file petitions on behalf of civil jurisdictions, as well as Metropolitan Statistical Areas or Micropolitan Statistical Areas. The addresses of State workforce agencies are available on the ETA Web site at: *http://www.doleta.gov/programs/lsa.cfm.* State Workforce Agencies may submit petitions in electronic format to *wright.samuel.e@dol.gov,* or in hard copy to the U.S. Department of Labor, Employment and Training Administration, Office of Workforce Investment, 200 Constitution Avenue, NW., Room S–4231, Washington, DC 20210. Data collection for the petition is approved under OMB 1205–0207, expiration date March 31, 2011.

Signed at Washington, D.C. this 21st day of October, 2009.

Jane Oates,

Assistant Secretary for Employment and Training Administration.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED

Alabama	
Balance of Dallas County, AL	Dallas County, AL.
Balance of Russell County, AL	Russell County, AL.
Barbour County, AL	Barbour County, AL
Bullock County, AL	Bullock County, AL.
Butler County, AL	Butler County, AL.
Chambers County, AL	Chambers County, AL.
Choctaw County, AL	Choctaw County, AL.
Clarke County, AL	Clarke County, AL.
Conecuh County, AL	Conecuh County, AL.
Coosa County, AL	Coosa County, AL.
Dallas County, AL	Dallas County, AL.
Greene County, AL	Greene County, AL.
Lamar County, AL	Lamar County, AL.
Lowndes County, AL	Lowndes County, AL.
Monroe County, AL	Monroe County, AL.
Perry County, AL	Perry County, AL.
Prichard City, AL	Mobile County, AL.
Russell County, AL	Russell County, AL.
Selma City, AL	Dallas County, AL.
Sumter County, AL	Sumter County, AL.
Washington County, AL	Washington County, AL.
Wilcox County, AL	Wilcox County, AL.
Winston County, AL	Winston County, AL.
Alaska	
Aleutians East Borough, AK	Aleutians East Borough, AK.
Bethel Census Area, AK	Bethel Census Area, AK.
Dillingham Census Area, AK	Dillingham Census Area, AK.
Fairbanks City, AK	Fairbanks North Star Borough, AK.
Haines Borough, AK	Haines Borough, AK.
Kenai Peninsula Borough, AK	Kenai Peninsula Borough, AK.
Kodiak Island Borough, AK	Kodiak Island Borough, AK.
Lake and Peninsula Borough, AK	Lake and Peninsula Borough, AK.
Matanuska-Susitna Borough, AK	Matanuska-Susitna Borough, AK.
Nome Census Area, AK	Nome Census Area, AK.
Northwest Arctic Borough, AK	Northwest Arctic Borough, AK.
Prince of Wales-Outer Ketchikan Census Area, AK	Prince of Wales-Outer Ketchikan Census Area, AK.
Skagway-Hoonah-Angoon Census Area, AK	Skagway-Hoonah-Angoon Census Area, AK.
Southeast Fairbanks Census Area, AK	Southeast Fairbanks Census Area, AK.
Valdez-Cordova Census Area, AK	Valdez-Cordova Census Area, AK.
Wade Hampton Census Area, AK	Wade Hampton Census Area, AK.
Wrangell-Petersburg Census Area, AK	Wrangell-Petersburg Census Area, AK.
Yakutat Borough, AK	Yakutat Borough, AK.
Yukon-Koyukuk Census Area, AK	Yukon-Koyukuk Census Area, AK.
Arizona	
Apache County, AZ	Apache County, AZ.
Balance of Cochise County, AZ	Cochise County, AZ.
Balance of Coconino County, AZ	Coconino County, AZ.
Balance of Maricopa County, AZ	Maricopa County, AZ.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

Balance of Mohave County, AZ	Mohave County, AZ.
Balance of Pinal County, AZ	Pinal County, AZ.
Navajo County, AZ	Navajo County, AZ.
Santa Cruz County, AZ	Santa Cruz County, AZ.
Yuma City, AZ	Yuma County, AZ.
Yuma County, AZ	Yuma County, AZ.
Arkansas	
Arkansas County, AR	Arkansas County, AR.
Ashley County, AR	Ashley County, AR.
Bradley County, AR	Bradley County, AR.
Chicot County, AR	Chicot County, AR.
Clay County, AR	Clay County, AR.
Columbia County, AR	Columbia County, AR.
Crittenden County, AR	Crittenden County, AR.
Cross County, AR	Cross County, AR.
Dallas County, AR	Dallas County, AR.
Desha County, AR	Desha County, AR.
Drew County, AR	Drew County, AR.
El Dorado City, AR	Union County, AR.
Hot Springs City, AR	Garland County, AR.
Independence County, AR	Independence County, AR.
Jackson County, AR	Jackson County, AR.
Jefferson County, AR	Jefferson County, AR.
Lafayette County, AR	Lafayette County, AR.
Lawrence County, AR	Lawrence County, AR.
Lee County, AR	Lee County, AR.
Lincoln County, AR	Lincoln County, AR.
Mississippi County, AR	Mississippi County, AR.
Ouachita County, AR	Ouachita County, AR.
Phillips County, AR	Phillips County, AR.
Pine Bluff City, AR	Jefferson County, AR.
Poinsett County, AR	Poinsett County, AR.
Randolph County, AR	Randolph County, AR.
Sharp County, AR	Sharp County, AR.
St. Francis County, AR	St. Francis County, AR.
Union County, AR	Union County, AR.
West Memphis City, AR	Crittenden County, AR.
Woodruff County, AR	Woodruff County, AR.
California	
Adelanto City, CA	San Bernardino County, CA.
Alpine County, CA	Alpine County, CA.
Amador County, CA	Amador County, CA.
Apple Valley Town, CA	San Bernardino County, CA.
Atwater City, CA	Merced County, CA.
Azusa City, CA	Los Angeles County, CA.
Balance of Placer County, CA	Placer County, CA.
Balance of Santa Clara County, CA	Santa Clara County, CA.
Balance of Santa Cruz County, CA	Santa Cruz County, CA.
Balance of Solano County, CA	Solano County, CA.
Balance of Ventura County, CA	Ventura County, CA.
Baldwin Park City, CA	Los Angeles County, CA.
Banning City, CA	Riverside County, CA.
Beaumont City, CA	Riverside County, CA.
Bell City, CA	Los Angeles County, CA.
Bell Gardens City, CA	Los Angeles County, CA.
Bellflower City, CA	Los Angeles County, CA.
Butte County, CA	Butte County, CA.
Calaveras County, CA	Calaveras County, CA.
Calexico City, CA	Imperial County, CA.
Carson City, CA	Los Angeles County, CA.
Cathedral City City, CA	Riverside County, CA.
Ceres City, CA	Stanislaus County, CA.
Chico City, CA	Butte County, CA.
Coachella City, CA	Riverside County, CA.
Colton City, CA	San Bernardino County, CA.
Colusa County, CA	Colusa County, CA.
Compton City, CA	Los Angeles County, CA.
Cudahy City, CA	Los Angeles County, CA.
Del Norte County, CA	Del Norte County, CA.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

Delano City, CA	Kern County, CA.
East Palo Alto City, CA	San Mateo County, CA.
El Cajon City, CA	San Diego County, CA.
El Centro City, CA	Imperial County, CA.
El Monte City, CA	Los Angeles County, CA.
Eureka City, CA	Humboldt County, CA.
Fairfield City, CA	Solano County, CA.
Fontana City, CA	San Bernardino County, CA.
Fresno City, CA	Fresno County, CA.
Fresno County, CA	Fresno County, CA.
Gilroy City, CA	Santa Clara County, CA.
Glenn County, CA	Glenn County, CA.
Hanford City, CA	Kings County, CA.
Hawthorne City, CA	Los Angeles County, CA.
Hemet City, CA	Riverside County, CA.
Hesperia City, CA	San Bernardino County, CA.
Highland City, CA	San Bernardino County, CA.
Hollister City, CA	San Benito County, CA.
Humboldt County, CA	Humboldt County, CA.
Huntington Park City, CA	Los Angeles County, CA.
Imperial Beach City, CA	San Diego County, CA.
Imperial County, CA	Imperial County, CA.
Indio City, CA	Riverside County, CA.
Inglewood City, CA	Los Angeles County, CA.
Kern County, CA	Kern County, CA.
Kings County, CA	Kings County, CA.
La Puente City, CA	Los Angeles County, CA.
Lake County, CA	Lake County, CA.
Lake Elsinore City, CA	Riverside County, CA.
Lancaster City, CA	Los Angeles County, CA.
Lassen County, CA	Lassen County, CA.
Lawndale City, CA	Los Angeles County, CA.
Lemon Grove City, CA	San Diego County, CA.
Lincoln City, CA	Placer County, CA.
Lodi City, CA	San Joaquin County, CA.
Lompoc City, CA	Santa Barbara County, CA.
Long Beach City, CA	Los Angeles County, CA.
Los Angeles City, CA	Los Angeles County, CA.
Los Angeles County, CA	Los Angeles County, CA.
Los Banos City, CA	Merced County, CA.
Lynwood City, CA	Los Angeles County, CA.
Madera City, CA	Madera County, CA.
Madera County, CA	Madera County, CA.
Manteca City, CA	San Joaquin County, CA.
Mariposa County, CA	Mariposa County, CA.
Maywood City, CA	Los Angeles County, CA.
Merced City, CA	Merced County, CA.
Merced County, CA	Merced County, CA.
Modesto City, CA	Stanislaus County, CA.
Modoc County, CA	Modoc County, CA.
Montclair City, CA	San Bernardino County, CA.
Montebello City, CA	Los Angeles County, CA.
Monterey Park City, CA	Los Angeles County, CA.
Moreno Valley City, CA	Riverside County, CA.
Morgan Hill City, CA	Santa Clara County, CA.
National City City, CA	San Diego County, CA.
Norwalk City, CA	Los Angeles County, CA.
Oakland City, CA	Alameda County, CA.
Ontario City, CA	San Bernardino County, CA.
Oxnard City, CA	Ventura County, CA.
Palmdale City, CA	Los Angeles County, CA.
Paramount City, CA	Los Angeles County, CA.
Perris City, CA	Riverside County, CA.
Pittsburg City, CA	Contra Costa County, CA.
Plumas County, CA	Plumas County, CA.
Pomona City, CA	Los Angeles County, CA.
Porterville City, CA	Tulare County, CA.
Rancho Cordova City, CA	Sacramento County, CA.
Redding City, CA	Shasta County, CA.
Rialto City, CA	San Bernardino County, CA.
Richmond City, CA	Contra Costa County, CA.
Riverside City, CA	Riverside County, CA.
Riverside County, CA	Riverside County, CA.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

Sacramento City, CA	Sacramento County, CA.
Sacramento County, CA	Sacramento County, CA.
Salinas City, CA	Monterey County, CA.
San Benito County, CA	San Benito County, CA.
San Bernardino City, CA	San Bernardino County, CA.
San Bernardino County, CA	San Bernardino County, CA.
San Jacinto City, CA	Riverside County, CA.
San Joaquin County, CA	San Joaquin County, CA.
San Pablo City, CA	Contra Costa County, CA.
Sanger City, CA	Fresno County, CA.
Santa Ana City, CA	Orange County, CA.
Santa Cruz County, CA	Santa Cruz County, CA.
Santa Maria City, CA	Santa Barbara County, CA.
Santa Paula City, CA	Ventura County, CA.
Shasta County, CA	Shasta County, CA.
Sierra County, CA	Sierra County, CA.
Siskiyou County, CA	Siskiyou County, CA.
Soledad City, CA	Monterey County, CA.
South Gate City, CA	Los Angeles County, CA.
Stanislaus County, CA	Stanislaus County, CA.
Stanton City, CA	Orange County, CA.
Stockton City, CA	San Joaquin County, CA.
Suisun City City, CA	Solano County, CA.
Sutter County, CA	Sutter County, CA.
Tehama County, CA	Tehama County, CA.
Trinity County, CA	Trinity County, CA.
Tulare City, CA	Tulare County, CA.
Tulare County, CA	Tulare County, CA.
Tuolumne County, CA	Tuolumne County, CA.
Turlock City, CA	Stanislaus County, CA.
Twentynine Palms City, CA	San Bernardino County, CA.
Vallejo City, CA	Solano County, CA.
Victorville City, CA	San Bernardino County, CA.
Watsonville City, CA	Santa Cruz County, CA.
West Sacramento City, CA	Yolo County, CA.
Woodland City, CA	Yolo County, CA.
Yolo County, CA	Yolo County, CA.
Yuba City City, CA	Sutter County, CA.
Yuba County, CA	Yuba County, CA.
Colorado	
Balance of El Paso County, CO	El Paso County, CO.
Commerce City City, CO	Adams County, CO.
Conejos County, CO	Conejos County, CO.
Costilla County, CO	Costilla County, CO.
Crowley County, CO	Crowley County, CO.
Saguache County, CO	Saguache County, CO.
Connecticut	
Ansonia City, CT	Ansonia City, CT.
Bridgeport City, CT	Bridgeport City, CT.
East Hartford Town, CT	East Hartford Town, CT.
Hartford City, CT	Hartford City, CT.
Killingly Town, CT	Killingly Town, CT.
Meriden City, CT	Meriden City, CT.
New Britain City, CT	New Britain City, CT.
New Haven City, CT	New Haven City, CT.
New London City, CT	New London City, CT.
Plainfield Town, CT	Plainfield Town, CT.
Putnam Town, CT	Putnam Town, CT.
Waterbury City, CT	Waterbury City, CT.
Windham County, CT	Windham County, CT.
Delaware	
Wilmington City, DE	New Castle County, DE.
District of Columbia	
District of Columbia	District of Columbia.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

Florida	
Balance of Bay County, FL	Bay County, FL.
Balance of Brevard County, FL	Brevard County, FL.
Balance of Broward County, FL	Broward County, FL.
Balance of Duval County, FL	Duval County, FL.
Balance of Escambia County, FL	Escambia County, FL.
Balance of Manatee County, FL	Manatee County, FL.
Balance of Marion County, FL	Marion County, FL.
Balance of Osceola County, FL	Osceola County, FL.
Balance of Palm Beach County, FL	Palm Beach County, FL.
Balance of Pinellas County, FL	Pinellas County, FL.
Balance of Polk County, FL	Polk County, FL.
Balance of Sarasota County, FL	Sarasota County, FL.
Balance of Volusia County, FL	Volusia County, FL.
Charlotte County, FL	Charlotte County, FL.
Citrus County, FL	Citrus County, FL.
Flagler County, FL	Flagler County, FL.
Fort Pierce City, FL	St. Lucie County, FL.
Hendry County, FL	Hendry County, FL.
Hernando County, FL	Hernando County, FL.
Hialeah City, FL	Miami-Dade County, FL.
Indian River County, FL	Indian River County, FL.
Lee County, FL	Lee County, FL.
Madison County, FL	Madison County, FL.
Miami Gardens City, FL	Miami-Dade County, FL.
Okeechobee County, FL	Okeechobee County, FL.
Palm Coast City, FL	Flagler County, FL.
Port St. Lucie City, FL	St. Lucie County, FL.
Georgia	
Albany City, GA	Dougherty County, GA.
Atkinson County, GA	Atkinson County, GA.
Atlanta City, GA	Fulton and DeKalb Counties.
Augusta-Richmond County (consolidated) City, GA	Richmond County, GA.
Balance of DeKalb County, GA	DeKalb County, GA.
Balance of Douglas County, GA	Douglas County, GA.
Balance of Fulton County, GA	Fulton County, GA.
Balance of Liberty County, GA	Liberty County, GA.
Balance of Peach County, GA	Peach County, GA.
Balance of Whitfield County, GA	Whitfield County, GA.
Baldwin County, GA	Baldwin County, GA.
Ben Hill County, GA	Ben Hill County, GA.
Burke County, GA	Burke County, GA.
Butts County, GA	Butts County, GA.
Calhoun County, GA	Calhoun County, GA.
Chattahoochee County, GA	Chattahoochee County, GA.
Chattooga County, GA	Chattooga County, GA.
Clay County, GA	Clay County, GA.
Clayton County, GA	Clayton County, GA.
Coffee County, GA	Coffee County, GA.
Cook County, GA	Cook County, GA.
Crisp County, GA	Crisp County, GA.
Dalton City, GA	Whitfield County, GA.
Decatur County, GA	Decatur County, GA.
Dougherty County, GA	Dougherty County, GA.
East Point City, GA	Fulton County, GA.
Elbert County, GA	Elbert County, GA.
Emanuel County, GA	Emanuel County, GA.
Hancock County, GA	Hancock County, GA.
Hart County, GA	Hart County, GA.
Heard County, GA	Heard County, GA.
Irwin County, GA	Irwin County, GA.
Jasper County, GA	Jasper County, GA.
Jeff Davis County, GA	Jeff Davis County, GA.
Jefferson County, GA	Jefferson County, GA.
Jenkins County, GA	Jenkins County, GA.
Johnson County, GA	Johnson County, GA.
LaGrange City, GA	Troup County, GA.
Lawrenceville City, GA	Gwinnett County, GA.
Lincoln County, GA	Lincoln County, GA.
Macon City, GA	Bibb and Jones, Counties.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

Macon County, GA	Macon County, GA.
McDuffie County, GA	McDuffie County, GA.
Meriwether County, GA	Meriwether County, GA.
Newton County, GA	Newton County, GA.
Quitman County, GA	Quitman County, GA.
Randolph County, GA	Randolph County, GA.
Richmond County, GA	Richmond County, GA.
Rome City, GA	Floyd County, GA.
Schley County, GA	Schley County, GA.
Screven County, GA	Screven County, GA.
Seminole County, GA	Seminole County, GA.
Spalding County, GA	Spalding County, GA.
Statesboro City, GA	Bulloch County, GA.
Stewart County, GA	Stewart County, GA.
Sumter County, GA	Sumter County, GA.
Talbot County, GA	Talbot County, GA.
Taliaferro County, GA	Taliaferro County, GA.
Taylor County, GA	Taylor County, GA.
Telfair County, GA	Telfair County, GA.
Terrell County, GA	Terrell County, GA.
Treutlen County, GA	Treutlen County, GA.
Troup County, GA	Troup County, GA.
Turner County, GA	Turner County, GA.
Twiggs County, GA	Twiggs County, GA.
Upson County, GA	Upson County, GA.
Warren County, GA	Warren County, GA.
Washington County, GA	Washington County, GA.
Wayne County, GA	Wayne County, GA.
Wilcox County, GA	Wilcox County, GA.
Wilkes County, GA	Wilkes County, GA.
Idaho	
Adams County, ID	Adams County, ID.
Balance of Canyon County, ID	Canyon County, ID.
Benewah County, ID	Benewah County, ID.
Boundary County, ID	Boundary County, ID.
Clearwater County, ID	Clearwater County, ID.
Shoshone County, ID	Shoshone County, ID.
Valley County, ID	Valley County, ID.
Illinois	
Alexander County, IL	Alexander County, IL.
Alton City, IL	Madison County, IL.
Balance of DeKalb County, IL	DeKalb County, IL.
Balance of Jackson County, IL	Jackson County, IL.
Balance of Kendall County, IL	Kendall County, IL.
Balance of Knox County, IL	Knox County, IL.
Belleville City, IL	St. Clair County, IL.
Belvidere City, IL	Boone County, IL.
Berwyn City, IL	Cook County, IL.
Bond County, IL	Bond County, IL.
Boone County, IL	Boone County, IL.
Calhoun County, IL	Calhoun County, IL.
Calumet City City, IL	Cook County, IL.
Carpentersville village, IL	Kane County, IL.
Chicago City, IL	Cook County, IL.
Chicago Heights City, IL	Cook County, IL.
Cicero Town, IL	Cook County, IL.
Clark County, IL	Clark County, IL.
Clay County, IL	Clay County, IL.
Crawford County, IL	Crawford County, IL.
Cumberland County, IL	Cumberland County, IL.
Danville City, IL	Vermilion County, IL.
Decatur City, IL	Macon County, IL.
Dolton village, IL	Cook County, IL.
East St. Louis City, IL	St. Clair County, IL.
Edgar County, IL	Edgar County, IL.
Elgin City, IL	Cook and Kane Counties, IL.
Fayette County, IL	Fayette County, IL.
Franklin County, IL	Franklin County, IL.
Freeport City, IL	Stephenson County, IL.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

Fulton County, IL	Fulton County, IL.
Galesburg City, IL	Knox County, IL.
Gallatin County, IL	Gallatin County, IL.
Granite City City, IL	Madison County, IL.
Grundy County, IL	Grundy County, IL.
Hamilton County, IL	Hamilton County, IL.
Hancock County, IL	Hancock County, IL.
Hardin County, IL	Hardin County, IL.
Harvey City, IL	Cook County, IL.
Henderson County, IL	Henderson County, IL.
Johnson County, IL	Johnson County, IL.
Joliet City, IL	Will County, IL.
Kankakee City, IL	Kankakee County, IL.
Kankakee County, IL	Kankakee County, IL.
La Salle County, IL	La Salle County, IL.
Lansing village, IL	Cook County, IL.
Lawrence County, IL	Lawrence County, IL.
Lee County, IL	Lee County, IL.
Macon County, IL	Macon County, IL.
Macoupin County, IL	Macoupin County, IL.
Madison County, IL	Madison County, IL.
Marion County, IL	Marion County, IL.
Mason County, IL	Mason County, IL.
Massac County, IL	Massac County, IL.
Maywood village, IL	Cook County, IL.
Mercer County, IL	Mercer County, IL.
Montgomery County, IL	Montgomery County, IL.
North Chicago City, IL	Lake County, IL.
Ogle County, IL	Ogle County, IL.
Park Forest village, IL	Cook and Will Counties, IL.
Perry County, IL	Perry County, IL.
Pope County, IL	Pope County, IL.
Pulaski County, IL	Pulaski County, IL.
Putnam County, IL	Putnam County, IL.
Randolph County, IL	Randolph County, IL.
Rockford City, IL	Winnebago County, IL.
Round Lake Beach village, IL	Lake County, IL.
Saline County, IL	Saline County, IL.
St. Clair County, IL	St. Clair County, IL.
Stephenson County, IL	Stephenson County, IL.
Union County, IL	Union County, IL.
Vermilion County, IL	Vermilion County, IL.
Wabash County, IL	Wabash County, IL.
Waukegan City, IL	Lake County, IL.
Whiteside County, IL	Whiteside County, IL.
Williamson County, IL	Williamson County, IL.
Winnebago County, IL	Winnebago County, IL.
Zion City, IL	Lake County, IL.
Indiana	
Anderson City, IN	Madison County, IN.
Balance of Delaware County, IN	Delaware County, IN.
Balance of LaPorte County, IN	LaPorte County, IN.
Balance of Marion County, IN	Marion County, IN.
Balance of Wayne County, IN	Wayne County, IN.
Blackford County, IN	Blackford County, IN.
Clay County, IN	Clay County, IN.
Crawford County, IN	Crawford County, IN.
DeKalb County, IN	DeKalb County, IN.
East Chicago City, IN	Lake County, IN.
Elkhart City, IN	Elkhart County, IN.
Elkhart County, IN	Elkhart County, IN.
Fayette County, IN	Fayette County, IN.
Gary City, IN	Lake County, IN.
Goshen City, IN	Elkhart County, IN.
Grant County, IN	Grant County, IN.
Hammond City, IN	Lake County, IN.
Henry County, IN	Henry County, IN.
Howard County, IN	Howard County, IN.
Kokomo City, IN	Howard County, IN.
LaGrange County, IN	LaGrange County, IN.
Lawrence County, IN	Lawrence County, IN.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

Madison County, IN	Madison County, IN.
Marion City, IN	Grant County, IN.
Miami County, IN	Miami County, IN.
Michigan City City, IN	LaPorte County, IN.
Muncie City, IN	Delaware County, IN.
Noble County, IN	Noble County, IN.
Randolph County, IN	Randolph County, IN.
Richmond City, IN	Wayne County, IN.
South Bend City, IN	St. Joseph County, IN.
Starke County, IN	Starke County, IN.
Steuben County, IN	Steuben County, IN.
Terre Haute City, IN	Vigo County, IN.
Vermillion County, IN	Vermillion County, IN.
Iowa	
Jasper County, IA	Jasper County, IA.
Kansas	
Kansas City City, KS	Wyandotte County, KS.
Leavenworth City, KS	Leavenworth County, KS.
Wyandotte County, KS	Wyandotte County, KS.
Kentucky	
Adair County, KY	Adair County, KY.
Allen County, KY	Allen County, KY.
Balance of Boyd County, KY	Boyd County, KY.
Balance of Henderson County, KY	Henderson County, KY.
Balance of Jefferson County, KY	Jefferson County, KY.
Bath County, KY	Bath County, KY.
Bell County, KY	Bell County, KY.
Boyle County, KY	Boyle County, KY.
Bracken County, KY	Bracken County, KY.
Breathitt County, KY	Breathitt County, KY.
Breckinridge County, KY	Breckinridge County, KY.
Bullitt County, KY	Bullitt County, KY.
Butler County, KY	Butler County, KY.
Carlisle County, KY	Carlisle County, KY.
Carroll County, KY	Carroll County, KY.
Carter County, KY	Carter County, KY.
Christian County, KY	Christian County, KY.
Clay County, KY	Clay County, KY.
Crittenden County, KY	Crittenden County, KY.
Cumberland County, KY	Cumberland County, KY.
Edmonson County, KY	Edmonson County, KY.
Elliott County, KY	Elliott County, KY.
Estill County, KY	Estill County, KY.
Fleming County, KY	Fleming County, KY.
Floyd County, KY	Floyd County, KY.
Fulton County, KY	Fulton County, KY.
Gallatin County, KY	Gallatin County, KY.
Grant County, KY	Grant County, KY.
Graves County, KY	Graves County, KY.
Grayson County, KY	Grayson County, KY.
Green County, KY	Green County, KY.
Harlan County, KY	Harlan County, KY.
Hickman County, KY	Hickman County, KY.
Hopkins County, KY	Hopkins County, KY.
Hopkinsville City, KY	Christian County, KY.
Jackson County, KY	Jackson County, KY.
Johnson County, KY	Johnson County, KY.
Knott County, KY	Knott County, KY.
Knox County, KY	Knox County, KY.
Lawrence County, KY	Lawrence County, KY.
Lee County, KY	Lee County, KY.
Leslie County, KY	Leslie County, KY.
Letcher County, KY	Letcher County, KY.
Lewis County, KY	Lewis County, KY.
Lincoln County, KY	Lincoln County, KY.
Lyon County, KY	Lyon County, KY.
Magoffin County, KY	Magoffin County, KY.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

Martin County, KY	Martin County, KY.
McCreary County, KY	McCreary County, KY.
McLean County, KY	McLean County, KY.
Meade County, KY	Meade County, KY.
Menifee County, KY	Menifee County, KY.
Metcalfe County, KY	Metcalfe County, KY.
Monroe County, KY	Monroe County, KY.
Montgomery County, KY	Montgomery County, KY.
Morgan County, KY	Morgan County, KY.
Muhlenberg County, KY	Muhlenberg County, KY.
Nelson County, KY	Nelson County, KY.
Nicholas County, KY	Nicholas County, KY.
Owsley County, KY	Owsley County, KY.
Pendleton County, KY	Pendleton County, KY.
Perry County, KY	Perry County, KY.
Powell County, KY	Powell County, KY.
Pulaski County, KY	Pulaski County, KY.
Rockcastle County, KY	Rockcastle County, KY.
Russell County, KY	Russell County, KY.
Spencer County, KY	Spencer County, KY.
Todd County, KY	Todd County, KY.
Trigg County, KY	Trigg County, KY.
Trimble County, KY	Trimble County, KY.
Washington County, KY	Washington County, KY.
Wayne County, KY	Wayne County, KY.
Whitley County, KY	Whitley County, KY.
Wolfe County, KY	Wolfe County, KY.
Louisiana	
East Carroll Parish, LA	Concordia Parish, LA.
Franklin Parish, LA	De Soto Parish, LA.
Madison Parish, LA	East Carroll Parish, LA.
Morehouse Parish, LA	Franklin Parish, LA.
Red River Parish, LA	Madison Parish, LA.
St. Helena Parish, LA	Morehouse Parish, LA.
St. James Parish, LA	Red River Parish, LA.
Tensas Parish, LA	St. Helena Parish, LA.
West Carroll Parish, LA	St. James Parish, LA.
Maine	
Aroostook County, ME	Aroostook County, ME.
Franklin County, ME	Franklin County, ME.
Oxford County, ME	Oxford County, ME.
Piscataquis County, ME	Piscataquis County, ME.
Somerset County, ME	Somerset County, ME.
Washington County, ME	Washington County, ME.
Maryland	
Dorchester County, MD	Dorchester County, MD.
Worcester County, MD	Worcester County, MD.
Massachusetts	
Adams Town, MA	Adams Town, MA.
Athol Town, MA	Athol Town, MA.
Bristol County, MA	Bristol County, MA.
Brockton City, MA	Brockton City, MA.
Fairhaven Town, MA	Fairhaven Town, MA.
Fall River City, MA	Fall River City, MA.
Fitchburg City, MA	Fitchburg City, MA.
Florida Town, MA	Florida Town, MA.
Gardner City, MA	Gardner City, MA.
Holyoke City, MA	Holyoke City, MA.
Lawrence City, MA	Lawrence City, MA.
Monroe Town, MA	Monroe Town, MA.
New Bedford City, MA	New Bedford City, MA.
North Adams City, MA	North Adams City, MA.
Provincetown Town, MA	Provincetown Town, MA.
Royalston Town, MA	Royalston Town, MA.
Southbridge Town, MA	Southbridge Town, MA.
Springfield City, MA	Springfield City, MA.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

Templeton Town, MA	Templeton Town, MA.
Truro Town, MA	Truro Town, MA.
Warren Town, MA	Warren Town, MA.
Webster Town, MA	Webster Town, MA.
Wellfleet Town, MA	Wellfleet Town, MA.
Westport Town, MA	Westport Town, MA.
Winchendon Town, MA	Winchendon Town, MA.
Michigan	
Alcona County, MI	Alcona County, MI.
Alger County, MI	Alger County, MI.
Allegan County, MI	Allegan County, MI.
Alpena County, MI	Alpena County, MI.
Antrim County, MI	Antrim County, MI.
Arenac County, MI	Arenac County, MI.
Balance of Clinton County, MI	Clinton County, MI.
Balance of Eaton County, MI	Eaton County, MI.
Balance of Midland County, MI	Midland County, MI.
Baraga County, MI	Baraga County, MI.
Battle Creek City, MI	Calhoun County, MI.
Bay City City, MI	Bay County, MI.
Bay County, MI	Bay County, MI.
Bedford Township (Monroe County), MI	Monroe County, MI.
Benzie County, MI	Benzie County, MI.
Berrien County, MI	Berrien County, MI.
Blackman Charter Township, MI	Jackson County, MI.
Branch County, MI	Branch County, MI.
Burton City, MI	Genesee County, MI.
Calhoun County, MI	Calhoun County, MI.
Cass County, MI	Cass County, MI.
Charlevoix County, MI	Charlevoix County, MI.
Cheboygan County, MI	Cheboygan County, MI.
Chesterfield Township, MI	Macomb County, MI.
Chippewa County, MI	Chippewa County, MI.
Clare County, MI	Clare County, MI.
Clinton Township (Macomb County), MI	Macomb County, MI.
Crawford County, MI	Crawford County, MI.
Delta County, MI	Delta County, MI.
Detroit City, MI	Wayne County, MI.
Dickinson County, MI	Dickinson County, MI.
East Lansing City, MI	Ingham County, MI.
Eastpointe City, MI	Macomb County, MI.
Emmet County, MI	Emmet County, MI.
Ferndale City, MI	Oakland County, MI.
Flint City, MI	Genesee County, MI.
Flint Township, MI	Genesee County, MI.
Genesee County, MI	Genesee County, MI.
Gladwin County, MI	Gladwin County, MI.
Gogebic County, MI	Gogebic County, MI.
Grand Rapids City, MI	Kent County, MI.
Grand Traverse County, MI	Grand Traverse County, MI.
Gratiot County, MI	Gratiot County, MI.
Harrison Township, MI	Macomb County, MI.
Highland Park City, MI	Wayne County, MI.
Hillsdale County, MI	Hillsdale County, MI.
Holland City, MI	Allegan County, MI.
Houghton County, MI	Houghton County, MI.
Huron County, MI	Huron County, MI.
Ingham County, MI	Ingham County, MI.
Inkster City, MI	Wayne County, MI.
Ionia County, MI	Ionia County, MI.
Iosco County, MI	Iosco County, MI.
Iron County, MI	Iron County, MI.
Jackson City, MI	Jackson County, MI.
Jackson County, MI	Jackson County, MI.
Kalamazoo City, MI	Kalamazoo County, MI.
Kalkaska County, MI	Kalkaska County, MI.
Kent County, MI	Kent County, MI.
Keweenaw County, MI	Keweenaw County, MI.
Lake County, MI	Lake County, MI.
Lansing City, MI	Eaton County, MI.
Lapeer County, MI	Lapeer County, MI.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

Lenawee County, MI	Lenawee County, MI.
Lincoln Park City, MI	Wayne County, MI.
Luce County, MI	Luce County, MI.
Mackinac County, MI	Mackinac County, MI.
Macomb County, MI	Macomb County, MI.
Macomb Township, MI	Macomb County, MI.
Madison Heights City, MI	Oakland County, MI.
Manistee County, MI	Manistee County, MI.
Marquette County, MI	Marquette County, MI.
Mason County, MI	Mason County, MI.
Mecosta County, MI	Mecosta County, MI.
Missaukee County, MI	Missaukee County, MI.
Monroe County, MI	Monroe County, MI.
Montcalm County, MI	Montcalm County, MI.
Montmorency County, MI	Montmorency County, MI.
Mount Pleasant City, MI	Isabella County, MI.
Muskegon City, MI	Muskegon County, MI.
Muskegon County, MI	Muskegon County, MI.
Newaygo County, MI	Newaygo County, MI.
Oak Park City, MI	Oakland County, MI.
Oakland County, MI	Oakland County, MI.
Oceana County, MI	Oceana County, MI.
Ogemaw County, MI	Ogemaw County, MI.
Ontonagon County, MI	Ontonagon County, MI.
Osceola County, MI	Osceola County, MI.
Oscoda County, MI	Oscoda County, MI.
Otsego County, MI	Otsego County, MI.
Ottawa County, MI	Ottawa County, MI.
Pontiac City, MI	Oakland County, MI.
Port Huron City, MI	St. Clair County, MI.
Presque Isle County, MI	Presque Isle County, MI.
Romulus City, MI	Wayne County, MI.
Roscommon County, MI	Roscommon County, MI.
Roseville City, MI	Macomb County, MI.
Saginaw City, MI	Saginaw County, MI.
Saginaw County, MI	Saginaw County, MI.
Sanilac County, MI	Sanilac County, MI.
Schoolcraft County, MI	Schoolcraft County, MI.
Shelby Charter Township (Macomb County), MI	Macomb County, MI.
Shiawassee County, MI	Shiawassee County, MI.
Southfield City, MI	Oakland County, MI.
St. Clair County, MI	St. Clair County, MI.
St. Clair Shores City, MI	Macomb County, MI.
St. Joseph County, MI	St. Joseph County, MI.
Taylor City, MI	Wayne County, MI.
Tuscola County, MI	Tuscola County, MI.
Van Buren County, MI	Van Buren County, MI.
Warren City, MI	Macomb County, MI.
Waterford Township, MI	Oakland County, MI.
Wayne County, MI	Wayne County, MI.
Wexford County, MI	Wexford County, MI.
Wyandotte City, MI	Wayne County, MI.
Wyoming City, MI	Kent County, MI.
Minnesota	
Aitkin County, MN	Aitkin County, MN.
Balance of Anoka County, MN	Anoka County, MN.
Balance of Benton County, MN	Benton County, MN.
Balance of Sherburne County, MN	Sherburne County, MN.
Balance of St. Louis County, MN	St. Louis County, MN.
Balance of Stearns County, MN	Stearns County, MN.
Becker County, MN	Becker County, MN.
Beltrami County, MN	Beltrami County, MN.
Cass County, MN	Cass County, MN.
Chisago County, MN	Chisago County, MN.
Clearwater County, MN	Clearwater County, MN.
Crow Wing County, MN	Crow Wing County, MN.
Grant County, MN	Grant County, MN.
Hubbard County, MN	Hubbard County, MN.
Isanti County, MN	Isanti County, MN.
Itasca County, MN	Itasca County, MN.
Kanabec County, MN	Kanabec County, MN.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

Koochiching County, MN	Koochiching County, MN.
Le Sueur County, MN	Le Sueur County, MN.
Mahnomen County, MN	Mahnomen County, MN.
Marshall County, MN	Marshall County, MN.
Meeker County, MN	Meeker County, MN.
Mille Lacs County, MN	Mille Lacs County, MN.
Morrison County, MN	Morrison County, MN.
Pennington County, MN	Pennington County, MN.
Pine County, MN	Pine County, MN.
Red Lake County, MN	Red Lake County, MN.
Wadena County, MN	Wadena County, MN.
Mississippi	
Adams County, MS	Adams County, MS.
Alcorn County, MS	Alcorn County, MS.
Amite County, MS	Amite County, MS.
Attala County, MS	Attala County, MS.
Benton County, MS	Benton County, MS.
Biloxi City, MS	Harrison County, MS.
Bolivar County, MS	Bolivar County, MS.
Calhoun County, MS	Calhoun County, MS.
Carroll County, MS	Carroll County, MS.
Chickasaw County, MS	Chickasaw County, MS.
Choctaw County, MS	Choctaw County, MS.
Claiborne County, MS	Claiborne County, MS.
Clarke County, MS	Clarke County, MS.
Clay County, MS	Clay County, MS.
Coahoma County, MS	Coahoma County, MS.
Columbus City, MS	Lowndes County, MS.
Copiah County, MS	Copiah County, MS.
Franklin County, MS	Franklin County, MS.
George County, MS	George County, MS.
Greene County, MS	Greene County, MS.
Greenville City, MS	Washington County, MS.
Grenada County, MS	Grenada County, MS.
Hattiesburg City, MS	Forrest and Lamar Counties, MS.
Holmes County, MS	Holmes County, MS.
Humphreys County, MS	Humphreys County, MS.
Issaquena County, MS	Issaquena County, MS.
Itawamba County, MS	Itawamba County, MS.
Jackson City, MS	Hinds,Madison and Rankin Counties.
Jasper County, MS	Jasper County, MS.
Jefferson County, MS	Jefferson County, MS.
Jefferson Davis County, MS	Jefferson Davis County, MS.
Kemper County, MS	Kemper County, MS.
Lauderdale County, MS	Lauderdale County, MS.
Lawrence County, MS	Lawrence County, MS.
Leake County, MS	Leake County, MS.
Lee County, MS	Lee County, MS.
Leflore County, MS	Leflore County, MS.
Lincoln County, MS	Lincoln County, MS.
Lowndes County, MS	Lowndes County, MS.
Marion County, MS	Marion County, MS.
Marshall County, MS	Marshall County, MS.
Meridian City, MS	Lauderdale County, MS.
Monroe County, MS	Monroe County, MS.
Montgomery County, MS	Montgomery County, MS.
Noxubee County, MS	Noxubee County, MS.
Oktibbeha County, MS	Oktibbeha County, MS.
Panola County, MS	Panola County, MS.
Pascagoula City, MS	Jackson County, MS.
Pearl River County, MS	Pearl River County, MS.
Perry County, MS	Perry County, MS.
Pike County, MS	Pike County, MS.
Pontotoc County, MS	Pontotoc County, MS.
Prentiss County, MS	Prentiss County, MS.
Quitman County, MS	Quitman County, MS.
Sharkey County, MS	Sharkey County, MS.
Sunflower County, MS	Sunflower County, MS.
Tallahatchie County, MS	Tallahatchie County, MS.
Tate County, MS	Tate County, MS.
Tippah County, MS	Tippah County, MS.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

Tishomingo County, MS	Tishomingo County, MS.
Tunica County, MS	Tunica County, MS.
Tupelo City, MS	Lee County, MS.
Union County, MS	Union County, MS.
Vicksburg City, MS	Warren County, MS.
Walthall County, MS	Walthall County, MS.
Warren County, MS	Warren County, MS.
Washington County, MS	Washington County, MS.
Wayne County, MS	Wayne County, MS.
Webster County, MS	Webster County, MS.
Wilkinson County, MS	Wilkinson County, MS.
Winston County, MS	Winston County, MS.
Yalobusha County, MS	Yalobusha County, MS.
Yazoo County, MS	Yazoo County, MS.
Missouri	
Balance of St. Louis County, MO	St. Louis County, MO.
Barton County, MO	Barton County, MO.
Bates County, MO	Cass County, MO.
Benton County, MO	Benton County, MO.
Butler County, MO	Butler County, MO.
Carter County, MO	Carter County, MO.
Crawford County, MO	Crawford County, MO.
Dallas County, MO	Dallas County, MO.
Dent County, MO	Dent County, MO.
Douglas County, MO	Douglas County, MO.
Dunklin County, MO	Dunklin County, MO.
Franklin County, MO	Franklin County, MO.
Gasconade County, MO	Gasconade County, MO.
Hickory County, MO	Hickory County, MO.
Jackson County, MO	Jackson County, MO.
Kansas City City, MO	Cass, Clay and Platte Counties, MO.
Laclede County, MO	Laclede County, MO.
Lincoln County, MO	Lincoln County, MO.
Linn County, MO	Linn County, MO.
Mississippi County, MO	Mississippi County, MO.
Monroe County, MO	Monroe County, MO.
Montgomery County, MO	Montgomery County, MO.
Morgan County, MO	Morgan County, MO.
New Madrid County, MO	New Madrid County, MO.
Pemiscot County, MO	Pemiscot County, MO.
Reynolds County, MO	Reynolds County, MO.
Ripley County, MO	Ripley County, MO.
Shannon County, MO	Shannon County, MO.
St. Clair County, MO	St. Clair County, MO.
St. Francois County, MO	St. Francois County, MO.
St. Louis City, MO	St. Louis City, MO.
Stoddard County, MO	Stoddard County, MO.
Stone County, MO	Stone County, MO.
Taney County, MO	Taney County, MO.
Warren County, MO	Warren County, MO.
Washington County, MO	Washington County, MO.
Wayne County, MO	Wayne County, MO.
Wright County, MO	Wright County, MO.
Montana	
Big Horn County, MT	Big Horn County, MT.
Glacier County, MT	Glacier County, MT.
Lincoln County, MT	Lincoln County, MT.
Roosevelt County, MT	Roosevelt County, MT.
Sanders County, MT	Sanders County, MT.
Nebraska	
Thurston County, NE	Thurston County, NE.
Nevada	
Balance of Clark County, NV	Balance of Clark County, NV.
Balance of Washoe County, NV	Balance of Washoe County, NV.
Lyon County, NV	Lyon County, NV.
Mineral County, NV	Mineral County, NV.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

Nye County, NV	Nye County, NV.
New Jersey	
Atlantic City City, NJ	Atlantic County, NJ.
Atlantic County, NJ	Atlantic County, NJ.
Balance of Camden County, NJ	Camden County, NJ.
Balance of Gloucester County, NJ	Gloucester County, NJ.
Bayonne City, NJ	Hudson County, NJ.
Camden City, NJ	Camden County, NJ.
Cape May County, NJ	Cape May County, NJ.
City of Orange Township, NJ	Essex County, NJ.
Cumberland County, NJ	Cumberland County, NJ.
East Orange City, NJ	Essex County, NJ.
Elizabeth City, NJ	Union County, NJ.
Garfield City, NJ	Bergen County, NJ.
Irvington Township, NJ	Essex County, NJ.
Manchester Township, NJ	Ocean County, NJ.
Millville City, NJ	Cumberland County, NJ.
Neptune Township, NJ	Monmouth County, NJ.
Newark City, NJ	Essex County, NJ.
Passaic City, NJ	Passaic County, NJ.
Paterson City, NJ	Passaic County, NJ.
Pennsauken Township, NJ	Camden County, NJ.
Perth Amboy City, NJ	Middlesex County, NJ.
Plainfield City, NJ	Union County, NJ.
Trenton City, NJ	Mercer County, NJ.
Union City City, NJ	Hudson County, NJ.
Vineland City, NJ	Cumberland County, NJ.
Winslow Township, NJ	Camden County, NJ.
New Mexico	
Balance of Sandoval County, NM	Sandoval County, NM.
Luna County, NM	Luna County, NM.
Mora County, NM	Mora County, NM.
New York	
Balance of Broome County, NY	Broome County, NY.
Balance of Erie County, NY	Erie County, NY.
Balance of Jefferson County, NY	Jefferson County, NY.
Balance of Niagara County, NY	Niagara County, NY.
Balance of Suffolk County, NY	Suffolk County, NY.
Balance of Warren County, NY	Warren County, NY.
Bronx County, NY	Bronx County, NY.
Buffalo City, NY	Erie County, NY.
Essex County, NY	Essex County, NY.
Franklin County, NY	Franklin County, NY.
Lockport City, NY	Niagara County, NY.
Montgomery County, NY	Montgomery County, NY.
Newburgh City, NY	Orange County, NY.
Niagara Falls City, NY	Niagara County, NY.
Orleans County, NY	Orleans County, NY.
Oswego County, NY	Oswego County, NY.
Rochester City, NY	Monroe County, NY.
Schoharie County, NY	Schoharie County, NY.
St. Lawrence County, NY	St. Lawrence County, NY.
North Carolina	
Alexander County, NC	Alexander County, NC.
Alleghany County, NC	Alleghany County, NC.
Anson County, NC	Anson County, NC.
Balance of Alamance County, NC	Alamance County, NC.
Balance of Cabarrus County, NC	Cabarrus County, NC.
Balance of Craven County, NC	Craven County, NC.
Balance of Cumberland County, NC	Cumberland County, NC.
Balance of Durham County, NC	Durham County, NC.
Balance of Forsyth County, NC	Forsyth County, NC.
Balance of Guilford County, NC	Guilford County, NC.
Balance of Iredell County, NC	Iredell County, NC.
Balance of Mecklenburg County, NC	Mecklenburg County, NC.
Balance of Pitt County, NC	Pitt County, NC.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

Balance of Wake County, NC	Wake County, NC.
Balance of Wilson County, NC	Wilson County, NC.
Beaufort County, NC	Beaufort County, NC.
Bertie County, NC	Bertie County, NC.
Bladen County, NC	Bladen County, NC.
Burke County, NC	Burke County, NC.
Caldwell County, NC	Caldwell County, NC.
Caswell County, NC	Caswell County, NC.
Catawba County, NC	Catawba County, NC.
Cherokee County, NC	Cherokee County, NC.
Chowan County, NC	Chowan County, NC.
Cleveland County, NC	Cleveland County, NC.
Columbus County, NC	Columbus County, NC.
Davidson County, NC	Davidson County, NC.
Edgecombe County, NC	Edgecombe County, NC.
Gaston County, NC	Gaston County, NC.
Gastonia City, NC	Gaston County, NC.
Graham County, NC	Graham County, NC.
Halifax County, NC	Halifax County, NC.
Hyde County, NC	Hyde County, NC.
Kinston City, NC	Lenoir County, NC.
Lee County, NC	Lee County, NC.
Lenoir County, NC	Lenoir County, NC.
McDowell County, NC	McDowell County, NC.
Mitchell County, NC	Mitchell County, NC.
Montgomery County, NC	Montgomery County, NC.
Nash County, NC	Nash County, NC.
Northampton County, NC	Northampton County, NC.
Person County, NC	Person County, NC.
Richmond County, NC	Richmond County, NC.
Robeson County, NC	Robeson County, NC.
Rockingham County, NC	Rockingham County, NC.
Rocky Mount City, NC	Edgecombe and Nash Counties, NC.
Rowan County, NC	Rowan County, NC.
Rutherford County, NC	Rutherford County, NC.
Salisbury City, NC	Rowan County, NC.
Scotland County, NC	Scotland County, NC.
Surry County, NC	Surry County, NC.
Swain County, NC	Swain County, NC.
Thomasville City, NC	Davidson County, NC.
Tyrrell County, NC	Tyrrell County, NC.
Vance County, NC	Vance County, NC.
Warren County, NC	Warren County, NC.
Washington County, NC	Washington County, NC.
Wilkes County, NC	Wilkes County, NC.
Wilson City, NC	Wilson County, NC.
Wilson County, NC	Wilson County, NC.
Yancey County, NC	Yancey County, NC.
North Dakota	
Benson County, ND	Benson County, ND.
Rolette County, ND	Rolette County, ND.
Ohio	
Adams County, OH	Adams County, OH.
Akron City, OH	Summit County, OH.
Allen County, OH	Allen County, OH.
Ashland County, OH	Ashland County, OH.
Ashtabula County, OH	Ashtabula County, OH.
Athens County, OH	Athens County, OH.
Balance of Lake County, OH	Lake County, OH.
Balance of Miami County, OH	Miami County, OH.
Balance of Portage County, OH	Portage County, OH.
Balance of Richland County, OH	Richland County, OH.
Balance of Wood County, OH	Wood County, OH.
Barberton City, OH	Summit County, OH.
Brook Park City, OH	Cuyahoga County, OH.
Brown County, OH	Brown County, OH.
Canton City, OH	Stark County, OH.
Carroll County, OH	Carroll County, OH.
Champaign County, OH	Champaign County, OH.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

Clark County, OH	Clark County, OH.
Cleveland City, OH	Cuyahoga County, OH.
Columbiana County, OH	Columbiana County, OH.
Coshocton County, OH	Coshocton County, OH.
Crawford County, OH	Crawford County, OH.
Cuyahoga County, OH	Cuyahoga County, OH.
Dayton City, OH	Montgomery County, OH.
Defiance County, OH	Defiance County, OH.
East Cleveland City, OH	Cuyahoga County, OH.
Elyria City, OH	Lorain County, OH.
Erie County, OH	Erie County, OH.
Euclid City, OH	Cuyahoga County, OH.
Fairborn City, OH	Greene County, OH.
Fulton County, OH	Fulton County, OH.
Gallia County, OH	Gallia County, OH.
Garfield Heights City, OH	Cuyahoga County, OH.
Guernsey County, OH	Guernsey County, OH.
Hardin County, OH	Hardin County, OH.
Harrison County, OH	Harrison County, OH.
Henry County, OH	Henry County, OH.
Highland County, OH	Highland County, OH.
Hocking County, OH	Hocking County, OH.
Huber Heights City, OH	Montgomery County, OH.
Huron County, OH	Huron County, OH.
Jackson County, OH	Jackson County, OH.
Jefferson County, OH	Jefferson County, OH.
Lima City, OH	Allen County, OH.
Lorain City, OH	Lorain County, OH.
Lorain County, OH	Lorain County, OH.
Lucas County, OH	Lucas County, OH.
Mahoning County, OH	Mahoning County, OH.
Mansfield City, OH	Richland County, OH.
Maple Heights City, OH	Cuyahoga County, OH.
Marion City, OH	Marion County, OH.
Marion County, OH	Marion County, OH.
Massillon City, OH	Stark County, OH.
Meigs County, OH	Meigs County, OH.
Middletown City, OH	Butler County, OH.
Monroe County, OH	Monroe County, OH.
Montgomery County, OH	Montgomery County, OH.
Morgan County, OH	Morgan County, OH.
Morrow County, OH	Morrow County, OH.
Muskingum County, OH	Muskingum County, OH.
Noble County, OH	Noble County, OH.
Ottawa County, OH	Ottawa County, OH.
Parma City, OH	Cuyahoga County, OH.
Perry County, OH	Perry County, OH.
Pickaway County, OH	Pickaway County, OH.
Pike County, OH	Pike County, OH.
Preble County, OH	Preble County, OH.
Richland County, OH	Richland County, OH.
Riverside City, OH	Montgomery County, OH.
Ross County, OH	Ross County, OH.
Sandusky City, OH	Erie County, OH.
Sandusky County, OH	Sandusky County, OH.
Scioto County, OH	Scioto County, OH.
Seneca County, OH	Seneca County, OH.
Springfield City, OH	Clark County, OH.
Stark County, OH	Stark County, OH.
Toledo City, OH	Lucas County, OH.
Trotwood City, OH	Montgomery County, OH.
Trumbull County, OH	Trumbull County, OH.
Van Wert County, OH	Van Wert County, OH.
Vinton County, OH	Vinton County, OH.
Warren City, OH	Trumbull County, OH.
Williams County, OH	Williams County, OH.
Wyandot County, OH	Wyandot County, OH.
Xenia City, OH	Greene County, OH.
Youngstown City, OH	Mahoning County, OH.
Zanesville City, OH	Muskingum County, OH.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

Oklahoma	
McCurtain County, OK	McCurtain County, OK.
Oregon	
Albany City, OR	Linn County, OR.
Baker County, OR	Baker County, OR.
Balance of Clackamas County, OR	Clackamas County, OR.
Balance of Lane County, OR	Lane County, OR.
Balance of Linn County, OR	Linn County, OR.
Balance of Marion County, OR	Marion County, OR.
Balance of Yamhill County, OR	Yamhill County, OR.
Columbia County, OR	Columbia County, OR.
Coos County, OR	Coos County, OR.
Crook County, OR	Crook County, OR.
Curry County, OR	Curry County, OR.
Deschutes County, OR	Deschutes County, OR.
Douglas County, OR	Douglas County, OR.
Grant County, OR	Grant County, OR.
Grants Pass City, OR	Josephine County, OR.
Harney County, OR	Harney County, OR.
Jackson County, OR	Jackson County, OR.
Jefferson County, OR	Jefferson County, OR.
Josephine County, OR	Josephine County, OR.
Klamath County, OR	Klamath County, OR.
Lake County, OR	Lake County, OR.
Linn County, OR	Linn County, OR.
Malheur County, OR	Malheur County, OR.
Medford City, OR	Jackson County, OR.
Springfield City, OR	Lane County, OR.
Union County, OR	Union County, OR.
Wallowa County, OR	Wallowa County, OR.
Pennsylvania	
Allentown City, PA	Lehigh County, PA.
Balance of Cambria County, PA	Cambria County, PA.
Balance of Lawrence County, PA	Lawrence County, PA.
Bedford County, PA	Bedford County, PA.
Cameron County, PA	Cameron County, PA.
Chester City, PA	Delaware County, PA.
Forest County, PA	Forest County, PA.
Fulton County, PA	Fulton County, PA.
Hazleton City, PA	Luzerne County, PA.
Johnstown City, PA	Cambria County, PA.
McKeesport City, PA	Allegheny County, PA.
Mercer County, PA	Mercer County, PA.
New Castle City, PA	Lawrence County, PA.
Philadelphia County/city, PA	Philadelphia County/city, PA.
Potter County, PA	Potter County, PA.
Reading City, PA	Berks County, PA.
York City, PA	York County, PA.
Puerto Rico	
Adjuntas Municipio, PR	Adjuntas Municipio, PR.
Aguada Municipio, PR	Aguada Municipio, PR.
Aguadilla Municipio, PR	Aguadilla Municipio, PR.
Aguas Buenas Municipio, PR	Aguas Buenas Municipio, PR.
Aibonito Municipio, PR	Aibonito Municipio, PR.
Anasco Municipio, PR	Anasco Municipio, PR.
Arecibo Municipio, PR	Arecibo Municipio, PR.
Arroyo Municipio, PR	Arroyo Municipio, PR.
Barceloneta Municipio, PR	Barceloneta Municipio, PR.
Barranquitas Municipio, PR	Barranquitas Municipio, PR.
Bayamon Municipio, PR	Bayamon Municipio, PR.
Cabo Rojo Municipio, PR	Cabo Rojo Municipio, PR.
Caguas Municipio, PR	Caguas Municipio, PR.
Camuy Municipio, PR	Camuy Municipio, PR.
Canovanas Municipio, PR	Canovanas Municipio, PR.
Carolina Municipio, PR	Carolina Municipio, PR.
Catano Municipio, PR	Catano Municipio, PR.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

Cayey Municipio, PR	Cayey Municipio, PR.
Ceiba Municipio, PR	Ceiba Municipio, PR.
Ciales Municipio, PR	Ciales Municipio, PR.
Cidra Municipio, PR	Cidra Municipio, PR.
Coamo Municipio, PR	Coamo Municipio, PR.
Comerio Municipio, PR	Comerio Municipio, PR.
Corozal Municipio, PR	Corozal Municipio, PR.
Culebra Municipio, PR	Culebra Municipio, PR.
Dorado Municipio, PR	Dorado Municipio, PR.
Fajardo Municipio, PR	Fajardo Municipio, PR.
Florida Municipio, PR	Florida Municipio, PR.
Guanica Municipio, PR	Guanica Municipio, PR
Guayama Municipio, PR	Guayama Municipio, PR.
Guayanilla Municipio, PR	Guayanilla Municipio, PR.
Guaynabo Municipio, PR	Guaynabo Municipio, PR.
Gurabo Municipio, PR	Gurabo Municipio, PR.
Hatillo Municipio, PR	Hatillo Municipio, PR.
Hormigueros Municipio, PR	Hormigueros Municipio, PR.
Humacao Municipio, PR	Humacao Municipio, PR.
Isabela Municipio, PR	Isabela Municipio, PR.
Jayuya Municipio, PR	Jayuya Municipio, PR.
Juana Diaz Municipio, PR	Juana Diaz Municipio, PR.
Juncos Municipio, PR	Juncos Municipio, PR.
Lajas Municipio, PR	Lajas Municipio, PR.
Lares Municipio, PR	Lares Municipio, PR.
Las Marias Municipio, PR	Las Marias Municipio, PR.
Las Piedras Municipio, PR	Las Piedras Municipio, PR.
Loiza Municipio, PR	Loiza Municipio, PR.
Luquillo Municipio, PR	Luquillo Municipio, PR.
Manati Municipio, PR	Manati Municipio, PR.
Maricao Municipio, PR	Maricao Municipio, PR.
Maunabo Municipio, PR	Maunabo Municipio, PR.
Mayaguez Municipio, PR	Mayaguez Municipio, PR.
Moca Municipio, PR	Moca Municipio, PR.
Morovis Municipio, PR	Morovis Municipio, PR.
Naguabo Municipio, PR	Naguabo Municipio, PR.
Naranjito Municipio, PR	Naranjito Municipio, PR.
Orocovis Municipio, PR	Orocovis Municipio, PR.
Patillas Municipio, PR	Patillas Municipio, PR.
Penuelas Municipio, PR	Penuelas Municipio, PR.
Ponce Municipio, PR	Ponce Municipio, PR.
Quebradillas Municipio, PR	Quebradillas Municipio, PR.
Rincon Municipio, PR	Rincon Municipio, PR.
Rio Grande Municipio, PR	Rio Grande Municipio, PR.
Sabana Grande Municipio, PR	Sabana Grande Municipio, PR.
Salinas Municipio, PR	Salinas Municipio, PR.
San German Municipio, PR	San German Municipio, PR.
San Juan Municipio, PR	San Juan Municipio, PR.
San Lorenzo Municipio, PR	San Lorenzo Municipio, PR.
San Sebastian Municipio, PR	San Sebastian Municipio, PR.
Santa Isabel Municipio, PR	Santa Isabel Municipio, PR.
Toa Alta Municipio, PR	Toa Alta Municipio, PR.
Toa Baja Municipio, PR	Toa Baja Municipio, PR.
Trujillo Alto Municipio, PR	Trujillo Alto Municipio, PR.
Utuado Municipio, PR	Utuado Municipio, PR.
Vega Alta Municipio, PR	Vega Alta Municipio, PR.
Vega Baja Municipio, PR	Vega Baja Municipio, PR.
Vieques Municipio, PR	Vieques Municipio, PR.
Villalba Municipio, PR	Villalba Municipio, PR.
Yabucoa Municipio, PR	Yabucoa Municipio, PR.
Yauco Municipio, PR	Yauco Municipio, PR.
Rhode Island	
Central Falls City, RI	Central Falls City, RI.
Coventry Town, RI	Coventry Town, RI.
Cranston City, RI	Cranston City, RI.
East Providence City, RI	East Providence City, RI.
Foster Town, RI	Foster Town, RI.
Hopkinton Town, RI	Hopkinton Town, RI.
Johnston Town, RI	Johnston Town, RI.
New Shoreham Town, RI	New Shoreham Town, RI.
North Providence Town, RI	North Providence Town, RI.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

Pawtucket City, RI	Pawtucket City, RI.
Providence City, RI	Providence City, RI.
Providence County, RI	Providence County, RI.
Scituate Town, RI	Scituate Town, RI.
Tiverton Town, RI	Tiverton Town, RI.
Warren Town, RI	Warren Town, RI.
West Warwick Town, RI	West Warwick Town, RI.
Woonsocket City, RI	Woonsocket City, RI.
South Carolina	
Abbeville County, SC	Abbeville County, SC.
Aiken City, SC	Aiken County, SC.
Allendale County, SC	Allendale County, SC.
Anderson City, SC	Anderson County, SC.
Anderson County, SC	Anderson County, SC.
Balance of Beaufort County, SC	Beaufort County, SC.
Bamberg County, SC	Bamberg County, SC.
Barnwell County, SC	Barnwell County, SC.
Calhoun County, SC	Calhoun County, SC.
Cherokee County, SC	Cherokee County, SC.
Chester County, SC	Chester County, SC.
Chesterfield County, SC	Chesterfield County, SC.
Clarendon County, SC	Clarendon County, SC.
Colleton County, SC	Colleton County, SC.
Columbia City, SC	Richland County, SC.
Darlington County, SC	Darlington County, SC.
Dillon County, SC	Dillon County, SC.
Edgefield County, SC	Edgefield County, SC.
Fairfield County, SC	Fairfield County, SC.
Florence City, SC	Florence County, SC.
Florence County, SC	Florence County, SC.
Georgetown County, SC	Georgetown County, SC.
Goose Creek City, SC	Berkeley County, SC.
Greenville City, SC	Greenville County, SC.
Greenwood County, SC	Greenwood County, SC.
Hampton County, SC	Hampton County, SC.
Lancaster County, SC	Lancaster County, SC.
Laurens County, SC	Laurens County, SC.
Lee County, SC	Lee County, SC.
Marion County, SC	Marion County, SC.
Marlboro County, SC	Marlboro County, SC.
McCormick County, SC	McCormick County, SC.
Myrtle Beach City, SC	Horry County, SC.
Newberry County, SC	Newberry County, SC.
Oconee County, SC	Oconee County, SC.
Orangeburg County, SC	Orangeburg County, SC.
Rock Hill City, SC	York County, SC.
Spartanburg City, SC	Spartanburg County, SC.
Spartanburg County, SC	Spartanburg County, SC.
Summerville Town, SC	Charleston and Dorchester Counties, SC.
Sumter City, SC	Sumter County, SC.
Sumter County, SC	Sumter County, SC.
Union County, SC	Union County, SC.
Williamsburg County, SC	Williamsburg County, SC.
York County, SC	York County, SC.
South Dakota	
Buffalo County, SD	Buffalo County, SD.
Dewey County, SD	Dewey County, SD.
Shannon County, SD	Shannon County, SD.
Todd County, SD	Todd County, SD.
Tennessee	
Balance of Carter County, TN	Carter County, TN.
Balance of Maury County, TN	Maury County, TN.
Benton County, TN	Benton County, TN.
Bledsoe County, TN	Bledsoe County, TN.
Campbell County, TN	Campbell County, TN.
Carroll County, TN	Carroll County, TN.
Claiborne County, TN	Claiborne County, TN.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

Clay County, TN	Clay County, TN.
Cleveland City, TN	Bradley County, TN.
Cocke County, TN	Cocke County, TN.
Columbia City, TN	Maury County, TN.
Cookeville City, TN	Putnam County, TN.
Crockett County, TN	Crockett County, TN.
Cumberland County, TN	Cumberland County, TN.
Decatur County, TN	Decatur County, TN.
Dyer County, TN	Dyer County, TN.
Fayette County, TN	Fayette County, TN.
Fentress County, TN	Fentress County, TN.
Gallatin City, TN	Sumner County, TN.
Gibson County, TN	Gibson County, TN.
Giles County, TN	Giles County, TN.
Grainger County, TN	Grainger County, TN.
Greene County, TN	Greene County, TN.
Grundy County, TN	Grundy County, TN.
Hancock County, TN	Hancock County, TN.
Hardeman County, TN	Hardeman County, TN.
Hardin County, TN	Hardin County, TN.
Haywood County, TN	Haywood County, TN.
Henderson County, TN	Henderson County, TN.
Henry County, TN	Henry County, TN.
Hickman County, TN	Hickman County, TN.
Houston County, TN	Houston County, TN.
Humphreys County, TN	Humphreys County, TN.
Jackson City, TN	Madison County, TN.
Jackson County, TN	Jackson County, TN.
Jefferson County, TN	Jefferson County, TN.
Kingsport City, TN	Hawkins and Sullivan Counties, TN.
Knoxville City, TN	Knox County, TN.
Lake County, TN	Lake County, TN.
Lauderdale County, TN	Lauderdale County, TN.
Lawrence County, TN	Lawrence County, TN.
Lewis County, TN	Lewis County, TN.
Macon County, TN	Macon County, TN.
Marion County, TN	Marion County, TN.
Marshall County, TN	Marshall County, TN.
Maryville City, TN	Blount County, TN.
Maury County, TN	Maury County, TN.
McMinn County, TN	McMinn County, TN.
McNairy County, TN	McNairy County, TN.
Meigs County, TN	Meigs County, TN.
Memphis City, TN	Shelby County, TN.
Monroe County, TN	Monroe County, TN.
Morgan County, TN	Morgan County, TN.
Morristown City, TN	Hamblen County, TN.
Obion County, TN	Obion County, TN.
Overton County, TN	Overton County, TN.
Perry County, TN	Perry County, TN.
Pickett County, TN	Pickett County, TN.
Polk County, TN	Polk County, TN.
Rhea County, TN	Rhea County, TN.
Scott County, TN	Scott County, TN.
Sequatchie County, TN	Sequatchie County, TN.
Smith County, TN	Smith County, TN.
Stewart County, TN	Stewart County, TN.
Tipton County, TN	Tipton County, TN.
Trousdale County, TN	Trousdale County, TN.
Unicoi County, TN	Unicoi County, TN.
Van Buren County, TN	Van Buren County, TN.
Warren County, TN	Warren County, TN.
Wayne County, TN	Wayne County, TN
Weakley County, TN	Weakley County, TN.
White County, TN	White County, TN.
Texas	
Balance of Coryell County, TX	Coryell County, TX.
Balance of Dallas County, TX	Dallas County, TX.
Balance of El Paso County, TX	El Paso County, TX.
Balance of Galveston County, TX	Galveston County, TX.
Balance of Jefferson County, TX	Jefferson County, TX.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

Balance of Nueces County, TX	Nueces County, TX.
Balance of Val Verde County, TX	Val Verde County, TX.
Balance of Webb County, TX	Webb County, TX.
Baytown City, TX	Harris County, TX.
Brownsville City, TX	Cameron County, TX.
Cameron County, TX	Cameron County, TX.
Coke County, TX	Coke County, TX.
Dimmit County, TX	Dimmit County, TX.
Eagle Pass City, TX	Maverick County, TX.
Hidalgo County, TX	Hidalgo County, TX.
Houston County, TX	Houston County, TX.
Lancaster City, TX	Dallas County, TX.
Loving County, TX	Loving County, TX.
Matagorda County, TX	Matagorda County, TX.
Maverick County, TX	Maverick County, TX.
Newton County, TX	Newton County, TX.
Polk County, TX	Polk County, TX.
Presidio County, TX	Presidio County, TX.
Sabine County, TX	Sabine County, TX.
San Juan City, TX	Hidalgo County, TX.
Socorro City, TX	El Paso County, TX.
Starr County, TX	Starr County, TX.
Texas City City, TX	Galveston County, TX.
Weslaco City, TX	Hidalgo County, TX.
Willacy County, TX	Willacy County, TX.
Zavala County, TX	Zavala County, TX.
Vermont	
Orleans County, VT	Orleans County, VT.
Virginia	
Covington City, VA	Carroll County, VA.
Danville City, VA	Covington City, VA.
Emporia City, VA	Danville City, VA.
Halifax County, VA	Emporia City, VA.
Henry County, VA	Halifax County, VA.
Martinsville City, VA	Henry County, VA.
Petersburg City, VA	Martinsville City, VA.
Pittsylvania County, VA	Page County, VA.
Williamsburg City, VA	Petersburg City, VA.
Washington	
Balance of Benton County, WA	Benton County, WA.
Balance of Franklin County, WA	Franklin County, WA.
Balance of Skagit County, WA	Skagit County, WA.
Balance of Spokane County, WA	Spokane County, WA.
Balance of Yakima County, WA	Yakima County, WA.
Bremerton City, WA	Kitsap County, WA.
Clallam County, WA	Clallam County, WA.
Clark County, WA	Clark County, WA.
Columbia County, WA	Columbia County, WA.
Cowlitz County, WA	Cowlitz County, WA.
Ferry County, WA	Ferry County, WA.
Grays Harbor County, WA	Grays Harbor County, WA.
Klickitat County, WA	Klickitat County, WA.
Lewis County, WA	Lewis County, WA.
Longview City, WA	Cowlitz County, WA.
Mason County, WA	Mason County, WA.
Okanogan County, WA	Okanogan County, WA.
Pacific County, WA	Pacific County, WA.
Pasco City, WA	Franklin County, WA.
Pend Oreille County, WA	Pend Oreille County, WA.
Skamania County, WA	Skamania County, WA.
Stevens County, WA	Stevens County, WA.
Wahkiakum County, WA	Wahkiakum County, WA.
Yakima County, WA	Yakima County, WA.
West Virginia	
Calhoun County, WV	Calhoun County, WV.
Clay County, WV	Clay County, WV.

LABOR SURPLUS AREAS; OCTOBER 1, 2009 THROUGH SEPTEMBER 30, 2010; ELIGIBLE LABOR SURPLUS AREAS; CIVIL JURISDICTIONS INCLUDED—Continued

McDowell County, WV	McDowell County, WV.
Mason County, WV	Mason County, WV.
Pocahontas County, WV	Pocahontas County, WV.
Wetzel County, WV	Wetzel County, WV.
Wisconsin	
Adams County, WI	Adams County, WI.
Bayfield County, WI	Bayfield County, WI.
Beloit City, WI	Rock County, WI.
Burnett County, WI	Burnett County, WI.
Forest County, WI	Forest County, WI.
Green Bay City, WI	Brown County, WI.
Iron County, WI	Iron County, WI.
Janesville City, WI	Rock County, WI.
Menominee County, WI	Menominee County, WI.
Milwaukee City, WI	Milwaukee County, WI.
Racine City, WI	Racine County, WI.
Rusk County, WI	Rusk County, WI.
Sawyer County, WI	Sawyer County, WI.
Washburn County, WI	Washburn County, WI.

[FR Doc. E9–26165 Filed 10–29–09; 8:45 am]

BILLING CODE 4510–FT–P

NATIONAL ARCHIVES AND RECORDS ADMINISTRATION

Advisory Committee on the Records of Congress

AGENCY: National Archives and Records Administration.

ACTION: Notice of Meeting.

SUMMARY: In accordance with the Federal Advisory Committee Act, as amended (5 U.S.C. Appendix 2) the National Archives and Records Administration (NARA) announces a meeting of the Advisory Committee on the Records of Congress. The committee advises NARA on the full range of programs, policies, and plans for the Center for Legislative Archives in the Office of Records Services.

DATES: November 16, 2009 from 10 a.m. to 11:30 a.m.

ADDRESSES: National Archives and Records Administration, Archivist's Boardroom.

FOR FURTHER INFORMATION CONTACT: Richard H. Hunt, Director; Center for Legislative Archives; (202) 357–5350.

SUPPLEMENTARY INFORMATION:

Agenda

(1) Chair's opening remarks—Clerk of the House.

(2) Recognition of Co-chair—Secretary of the Senate.

(3) Recognition of the Archivist of the United States.

(4) Approval of the minutes of the last meeting.

(5) Discussion of on-going projects and activities.

(6) Annual Report of the Center for Legislative Archives.

(7) Other current issues and new business.

The meeting is open to the public.

Dated: October 27, 2009.

Mary Ann Hadyka,

Committee Management Officer.

[FR Doc. E9–26281 Filed 10–29–09; 8:45 am]

BILLING CODE 7515–01–P

NATIONAL ARCHIVES AND RECORDS ADMINISTRATION

Records Schedules; Availability and Request for Comments

AGENCY: National Archives and Records Administration (NARA).

ACTION: Notice of availability of proposed records schedules; request for comments.

SUMMARY: The National Archives and Records Administration (NARA) publishes notice at least once monthly of certain Federal agency requests for records disposition authority (records schedules). Once approved by NARA, records schedules provide mandatory instructions on what happens to records when no longer needed for current Government business. They authorize the preservation of records of continuing value in the National Archives of the United States and the destruction, after a specified period, of records lacking administrative, legal, research, or other value. Notice is published for records schedules in which agencies propose to destroy records not previously authorized for disposal or reduce the retention period of records already authorized for disposal. NARA invites public comments on such records schedules, as required by 44 U.S.C. 3303a(a).

DATES: Requests for copies must be received in writing on or before November 30, 2009. Once the appraisal of the records is completed, NARA will send a copy of the schedule. NARA staff usually prepare appraisal memorandums that contain additional information concerning the records covered by a proposed schedule. These, too, may be requested and will be provided once the appraisal is completed. Requesters will be given 30 days to submit comments.

ADDRESSES: You may request a copy of any records schedule identified in this notice by contacting the Life Cycle Management Division (NWML) using one of the following means:

Mail: NARA (NWML), 8601 Adelphi Road, College Park, MD 20740–6001.

E-mail: request.schedule@nara.gov.

FAX: 301–837–3698.

Requesters must cite the control number, which appears in parentheses after the name of the agency which submitted the schedule, and must provide a mailing address. Those who desire appraisal reports should so indicate in their request.

FOR FURTHER INFORMATION CONTACT: Laurence Brewer, Director, Life Cycle Management Division (NWML), National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740–6001. *Telephone:* 301–837–1539. *E-mail: records.mgt@nara.gov.*

SUPPLEMENTARY INFORMATION: Each year Federal agencies create billions of records on paper, film, magnetic tape, and other media. To control this accumulation, agency records managers prepare schedules proposing retention periods for records and submit these schedules for NARA's approval, using the Standard Form (SF) 115, Request for Records Disposition Authority. These schedules provide for the timely transfer into the National Archives of historically valuable records and authorize the disposal of all other records after the agency no longer needs them to conduct its business. Some schedules are comprehensive and cover all the records of an agency or one of its major subdivisions. Most schedules, however, cover records of only one office or program or a few series of records. Many of these update previously approved schedules, and some include records proposed as permanent.

The schedules listed in this notice are media neutral unless specified otherwise. An item in a schedule is media neutral when the disposition instructions may be applied to records regardless of the medium in which the records are created and maintained. Items included in schedules submitted to NARA on or after December 17, 2007, are media neutral unless the item is limited to a specific medium. (*See* 36 CFR 1228.24(b)(3).)

No Federal records are authorized for destruction without the approval of the Archivist of the United States. This approval is granted only after a thorough consideration of their administrative use by the agency of origin, the rights of the Government and of private persons directly affected by the Government's activities, and whether or not they have historical or other value.

Besides identifying the Federal agencies and any subdivisions requesting disposition authority, this public notice lists the organizational unit(s) accumulating the records or indicates agency-wide applicability in the case of schedules that cover records that may be accumulated throughout an agency. This notice provides the control number assigned to each schedule, the total number of schedule items, and the number of temporary items (the records proposed for destruction). It also includes a brief description of the temporary records. The records schedule itself contains a full description of the records at the file unit level as well as their disposition. If NARA staff has prepared an appraisal memorandum for the schedule, it too includes information about the records. Further information about the disposition process is available on request.

Schedules Pending

1. Department of Agriculture, Economic Research Service (N1–354–09–1, 38 items, 26 temporary items). Routine correspondence files, background files for speeches, delegations of authority, management improvement program files, emergency preparedness records, minutes of lower level staff meetings, information technology plans, and other records relating to administrative matters and day-to-day operations. Proposed for permanent retention are such overall program and policy records as significant correspondence, speeches, legal opinions, records of boards and committees, minutes of high level staff meetings, directives, publications, and historical narratives.

2. Department of Defense, Defense Threat Reduction Agency (N1–374–09–1, 1 item, 1 temporary item). Master files associated with an electronic information system used to track such matters as manpower authorizations, recruitment actions, and security clearance requirements for positions.

3. Department of Defense, Defense Threat Reduction Agency (N1–374–09–2, 1 item, 1 temporary item). Investigative records, including reports, witness statements, and decisions. Records relate to agency employees and contractors suspected of malfeasance or other improper activities.

4. Department of Health and Human Services, Office of the Secretary) N1–468–09–5, 1 item, 1 temporary item). Master files of an electronic information system that contains information collection request forms and supporting documentation prepared to secure approval from the Office of Management Budget.

5. Department of Justice, Agency-wide (N1–60–09–31, 7 items, 7 temporary items). Master files associated with an electronic information system used to manage training. Included is data concerning course content, participants, and instructors.

6. Department of Justice, Criminal Division (N1–60–08–22, 1 item, 1 temporary item). Master files associated with an electronic information system used to track requests for special attorney search warrants and subpoenas.

7. Department of Justice, Federal Bureau of Investigation (N1–65–09–11, 3 items, 3 temporary items). This schedule reduces the retention period of inputs into the Terrorist Screening and Operations Unit Log System, which were previously approved for disposal. Also included are packets of information concerning watchlist individuals provided by other agencies.

8. Department of Justice, Federal Bureau of Investigation (N1–65–09–18, 4 items, 3 temporary items). Records related to testing and auditing an electronic collaboration tool used for communications relating to operations regarding Weapons of Mass Destruction Render Safe Operations. Communications relating to actual weapons of mass destruction events are proposed for permanent retention.

9. Department of Justice, Federal Bureau of Investigation (N1–65–09–23, 3 items, 3 temporary items). Preliminary Uniform Crime Reporting Program reports and audit logs. This schedule reduces the retention period of these records, which were previously approved for disposal. Also included are requests for copies of reports and related information. Final Uniform Crime Reporting reports were previously approved for permanent retention.

10. Department of Justice, Federal Bureau of Investigation (N1–65–09–26, 3 items, 3 temporary items). Master files, outputs, and audit records associated with an electronic information system that contains course evaluation data provided by participants.

11. Department of the Navy, United States Marine Corps (N1–127–08–1, 1 item, 1 temporary item). Master files associated with an electronic information system used to process separations of enlisted personnel from the reserve forces.

12. Department of the Navy, United States Marine Corps (N1–127–09–2, 1 item, 1 temporary item). Master files associated with an electronic information system used to track separations and retirements of officers and enlisted personnel.

13. Department of the Navy, United States Marine Corps (N1–127–09–4, 1 item, 1 temporary item). Master files associated with an electronic information system used in connection with force structure and manpower scenario development. Data includes unit tables of organization and information concerning personnel, including training received and physical fitness scores.

14. Department of the Navy, United States Marine Corps (N1–127–09–5, 1 item, 1 temporary item). Master files associated with an electronic information system containing modeling and decision support functionality required to support the manpower development process. Data includes unit tables of organization and information concerning personnel,

including training received and physical fitness scores.

15. Department of Transportation, Federal Highway Administration (N1–406–08–11, 30 items, 28 temporary items). Records of the Office of the Chief Counsel, including such records as administrative files, non-rulemaking notices, monthly reports, litigation files, tort files, and reference papers. Proposed for permanent retention are rulemaking notices and legal precedent files.

16. Department of Transportation, Federal Highway Administration (N1–406–09–15, 1 item, 1 temporary item). Master files associated with a Web-based electronic information system that contains examples of streamlining and stewardship practices adopted by States to fulfill their obligations under the National Environmental Policy Act.

17. Department of the Treasury, Departmental Offices (N1–56–09–18, 4 items, 4 temporary items). Master files, inputs, outputs, and system documentation associated with an electronic information system used to track Office of Counsel incoming correspondence.

18. Department of the Treasury, Community Development Financial Institution (N1–56–09–11, 3 items, 3 temporary items). Master files, outputs, and system documentation associated with an electronic information system used for compliance monitoring of monetary awards granted to financial institutions for community development purposes.

19. Department of the Treasury, Internal Revenue Service (N1–58–09–106, 2 items, 2 temporary items). Outputs and system documentation associated with an electronic information system used to generate reports based on electronic filings of business and individual tax returns.

20. Department of the Treasury, Internal Revenue Service (N1–58–09–107, 2 items, 2 temporary items). Master files and system documentation associated with an electronic information system used to process data relating to payments made by the Social Security Administration and Railroad Retirement Board.

21. Department of the Treasury, Internal Revenue Service (N1–58–09–108, 2 items, 2 temporary items). Master files and system documentation associated with an electronic information system used to maintain data from business tax returns that may be analyzed by field tax examiners.

22. Department of the Treasury, Internal Revenue Service (N1–58–09–109, 2 items, 2 temporary items). Master files and system documentation associated with an electronic information system used to maintain tax return data that may be analyzed by field tax examiners.

23. Department of the Treasury, Internal Revenue Service (N1–58–09–110, 3 items, 3 temporary items). Master files, outputs, and system documentation associated with an electronic information system used to provide support to taxpayers using the agency's electronic products.

24. Department of the Treasury, Internal Revenue Service (N1–58–09–113, 3 items, 3 temporary items). Master files, outputs, and system documentation associated with an electronic information system used to house and summarize data used for business performance analysis.

25. National Aeronautics and Space Administration, Agency-wide (N1–255–09–1, 573 items, 573 temporary items). Records relating to such matters as legal issues, procurement, program formulation and management, inspector general activities, financial management, property and supply, industrial relations, personnel administration, and transportation. Paper and other hard copies of these records were previously approved for disposal.

26. National Archives and Records Administration, Office of Presidential Libraries (DAA–0064–2010–0001, 4 items, 4 temporary items). Records included in an electronic information system used by Presidential libraries to document and manage items in their museum collections. Included is descriptive information concerning individual items, such as measurements, name of producer, and data concerning its acquisition, information concerning the use of items in exhibits, data concerning preservation actions, and information concerning people and publications related to items.

27. Securities and Exchange Commission, Division of Trading and Markets (N1–266–09–3, 1 item, 1 temporary item). Master files of an electronic information system used to track recommendations that result from inspections of the technology systems used by exchanges.

Dated: October 27, 2009.

Michael J. Kurtz,

Assistant Archivist for Records Services—Washington, DC.

[FR Doc. E9–26279 Filed 10–29–09; 8:45 am]

BILLING CODE 7515–01–P

NUCLEAR REGULATORY COMMISSION

[Docket No. 040–08502; NRC–2009–0036]

Notice of Application From Cogema Mining, Inc, for Consent to an Indirect Change of Control for Source Materials License SUA–1341, Opportunity To Provide Comments and To Request a Hearing

AGENCY: Nuclear Regulatory Commission.

ACTION: Notice of consideration of request from COGEMA Mining, Inc., for the indirect change of control of Source Material License SUA–1341 and opportunity to request a hearing.

DATES: A request for a hearing must be filed by November 19, 2009.

FOR FURTHER INFORMATION CONTACT: Ron C. Linton, Project Manager, Uranium Recovery Licensing Branch, Division of Waste Management and Environmental Protection, Office of Federal and State Materials and Environmental Management Programs, U.S. Nuclear Regulatory Commission, Washington, DC 20555. *Telephone:* (301) 415–7777; *fax number:* (301) 415–5369; *e-mail: ron.linton@nrc.gov.*

SUPPLEMENTARY INFORMATION:

I. Introduction

The Nuclear Regulatory Commission (NRC) is considering an application submitted on September 18, 2009, by Cogema Mining, Inc. (Cogema or the Applicant), requesting consent for an indirect change of control with respect to its NRC Materials License SUA–1341. Under this license, Cogema operates the Irigaray and Christensen Ranch in situ leach (ISL) uranium milling facilities that are located in Johnson and Campbell Counties, Wyoming. Cogema is a wholly owned subsidiary of Cogema Resources, Inc. (Cogema Resources), which is a wholly owned subsidiary of Areva NC. Cogema Resources is planning to sell Cogema to Uranium One Exploration U.S.A., Inc. (Uranium One), which, through several subsidiaries, is wholly owned by Uranium One, Inc.

On August 7, 2009, Uranium One, a Delaware Corporation, entered into a Purchase Agreement with Cogema Resources, a Delaware corporation, to acquire 100 percent of the shares in Cogema and all interests of Fuel International Trading Corporation (FITC), also a Delaware corporation. FITC's subsidiary, Malapai Resources Company, is a joint venture partner at the Wyoming ISL facilities with Cogema Resources. Consummation of the transaction would result in the indirect change of control of Cogema and license SUA–1341 from Cogema Resources to Uranium One. Cogema is requesting that the NRC consent to this change of control.

The application states that there would be no change to Cogema operations, its key operating personnel, or its licensed activities as a result of the transaction. After closing of the transaction, and if the indirect change of control is approved by the NRC, Cogema would continue to be the holder of license SUA–1341. Cogema would remain technically and financially qualified as the licensee and would continue to fulfill all responsibilities as the licensee. The Applicant states that no amendment to its license would be necessary in connection with the request for consent; however an administrative license amendment would be needed to reflect a change in the financial surety mechanism for License SUA–1341.

Pursuant to 10 CFR 40.46, no Part 40 license shall be transferred, assigned, or in any manner disposed of, either voluntarily or involuntarily, directly or indirectly, through transfer of control of the license to any person, unless the Commission, after securing full information, finds that the transfer is in accordance with the provisions of the Atomic Energy Act, and gives its consent in writing. An Environmental Assessment (EA) will not be performed for this proposed action because it falls within a class of actions categorically excluded from the requirement to perform an EA pursuant to 10 CFR 51.22(c)(21).

Approval of the indirect change of control is contingent upon receipt of the fully executed financial assurance instruments which are in form and substance satisfactory to NRC. Upon receipt of such instruments and a satisfactory completion of a safety review, the NRC staff plans to consent to the September 18, 2009 application by issuing the necessary order, along with a supporting safety evaluation report.

II. Opportunity To Request a Hearing

Any person whose interest may be affected if the September 18, 2009 application is approved and who desires to participate as a party in an NRC adjudicatory hearing must file a request for a hearing. The hearing request must include a specification of the contentions which the person seeks to have litigated in the hearing, and must be filed in accordance with the NRC E-Filing rule, which the NRC promulgated in August 28, 2007 (72 FR 49139). The E-Filing rule requires participants to submit and serve documents over the internet or, in some cases, to mail copies on electronic storage media. Participants may not submit paper copies of their filings unless they seek a waiver in accordance with the procedures described below.

To comply with the procedural requirements of E-Filing, at least ten (10) days prior to the filing deadline, the petitioner/requestor must contact the Office of the Secretary by e-mail at *HEARINGDOCKET@NRC.GOV,* or by calling (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/or (2) creation of an electronic docket for the proceeding (even in instances in which the petitioner/requestor (or its counsel or representative) already holds an NRC-issued digital ID certificate). Each petitioner/requestor will need to download the Workplace Forms Viewer™ to access the Electronic Information Exchange (EIE), a component of the E-Filing system. The Workplace Forms Viewer™ is free and is available at *http://www.nrc.gov/site-help/e-submittals/install-viewer.html.* 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.*

Once a petitioner/requestor has obtained a digital ID certificate, had a docket created, and downloaded the EIE viewer, it can then submit a request for hearing or petition for leave to intervene. Submissions should be in Portable Document Format (PDF) in accordance with NRC guidance available on the NRC public Web site at *http://www.nrc.gov/site-help/e-submittals.html.* A filing is considered complete at the time the filer submits its documents through EIE. To be timely, an electronic filing must be submitted to the EIE system no later than 11:59 p.m. Eastern Standard Time on the due date. Upon receipt of a transmission, the E-Filing system time-stamps the document and sends the submitter an e-mail notice confirming receipt of the document. The EIE system also distributes an e-mail notice that provides access to the document to the NRC 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 through the ''Contact Us'' link located on the NRC Web site at *http://www.nrc.gov/site-help/e-submittals.html* or by calling the NRC Meta-System Help Desk, which is available between 8 a.m. and 8 p.m., Eastern Time, Monday through Friday, excluding government holidays. The Meta-System Help Desk can be contacted by telephone at 1–866–672–7640 or by e-mail at *MSHD.Resource@nrc.gov.*

Participants who believe that they have a good cause for not submitting documents electronically must file a motion, in accordance with 10 CFR 2.302(g), with their initial paper filing requesting authorization to continue to submit documents in paper format. Such filings must be submitted by: (1) First class mail addressed to the Office of the Secretary of the Commission, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, Attention: Rulemaking and Adjudications Staff; or (2) courier, express mail, or expedited delivery service to the Office of the Secretary, Sixteenth Floor, One White Flint North, 11555 Rockville Pike, Rockville, Maryland, 20852, Attention: Rulemaking and Adjudications Staff. Participants filing a document in this manner are responsible for serving the document on all other participants. Filing is considered complete by first-class mail as of the time of deposit in the mail, or by courier, express mail, or expedited delivery service upon depositing the document with the provider of the service.

Non-timely requests and/or petitions and contentions will not be entertained absent a determination by the Commission, the presiding officer, or the Atomic Safety and Licensing Board that the petition and/or request should be granted and/or the contentions should be admitted based on a balancing of the factors specified in 10 CFR 2.309(c)(1)(i)–(viii). To be timely, filings must be submitted no later than 11:59 p.m. Eastern Standard Time on the due date.

Documents submitted in adjudicatory proceedings will appear in NRC's electronic hearing docket which is available to the public at *http://ehd.nrc.gov/EHD_Proceeding/home.asp,* unless excluded pursuant to an order of the Commission, an Atomic Safety and Licensing Board, or a Presiding Officer.

Participants are requested not to include social security numbers in their filings. Copyrighted works, except for limited excerpts that serve the purpose of the adjudicatory filings and would constitute a Fair Use application, should not be included in the submission.

The formal requirements for documents contained in 10 CFR 2.304(c)–(e) must be met. If the NRC grants an electronic document exemption in accordance with 10 CFR 2.302(g)(3), then the requirements for paper documents, set forth in 10 CFR 2.304(b) must be met.

In accordance with 10 CFR 2.309(b), a request for a hearing must be filed by November 19, 2009.

In addition to meeting other applicable requirements of 10 CFR 2.309, a request for a hearing filed by a person other than an applicant must state:

1. The name, address, and telephone number of the requestor;
2. The nature of the requestor's right under the Act to be made a party To the proceeding;
3. The nature and extent of the requestor's property, financial or other interest in the proceeding;
4. The possible effect of any decision or order that may be issued in the proceeding on the requestor's interest; and
5. The circumstances establishing that the request for a hearing is timely in accordance with 10 CFR 2.309(b).

In accordance with 10 CFR 2.309(f)(1), a request for hearing or petitions for leave to intervene must set forth with particularity the contentions sought to be raised. For each contention, the request or petition must:

1. Provide a specific statement of the issue of law or fact to be raised or controverted;
2. Provide a brief explanation of the basis for the contention;
3. Demonstrate that the issue raised in the contention is within the scope of the proceeding;
4. Demonstrate that the issue raised in the contention is material to the findings that the NRC must make to support the action that is involved in the proceeding;
5. Provide a concise statement of the alleged facts or expert opinions which support the requestor's/petitioner's position on the issue and on which the requestor/petitioner intends to rely to support its position on the issue; and
6. Provide sufficient information to show that a genuine dispute exists with the applicant on a material issue of law or fact. This information must include references to specific portions of the application that the requestor/petitioner disputes and the supporting reasons for each dispute, or, if the requestor/petitioner believes the application fails to contain information on a relevant matter as required by law, the identification of each failure and the supporting reasons for the requestor's/petitioner's belief.

In addition, in accordance with 10 CFR 2.309(f)(2), contentions must be based on documents or other information available at the time the petition is to be filed, such as the application, or other supporting document filed by an applicant or licensee, or otherwise available to the petitioner. Contentions may be amended or new contentions filed after the initial filing only with leave of the presiding officer.

Requestors/petitioners should, when possible, consult with each other in preparing contentions and combine similar subject matter concerns into a joint contention, for which one of the co-sponsoring requesters/petitioners is designated the lead representative. Further, in accordance with 10 CFR 2.309(f)(3), any requestor/petitioner who wishes to adopt a contention proposed by another requestor/petitioner must do so, in accordance with the E-Filing rule, within ten days of the date the contention is filed, and designate a representative who shall have the authority to act for the requestor/petitioner.

As indicated below, pursuant to 10 CFR 2.310(g), any hearing would be subject to the procedures set forth in 10 CFR Part 2, subpart M.

III. Opportunity To Provide Written Comments

Within 30 days from the date of publication of this notice, persons may submit written comments regarding the license transfer application, as provided for in 10 CFR 2.1305. The Commission will consider and, if appropriate, respond to these comments, but such comments will not otherwise constitute part of the decisional record. Comments should be submitted to the Secretary, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, *Attention:* Rulemakings and Adjudications Staff, and should cite the publication date and page number of this **Federal Register** notice. Comments received after 30 days will be considered if practicable to do so, but only those comments received on or before the due date can be assured consideration.

IV. Further Information

For further details with respect to the proposed action, see the applicant's Letter of Intent dated August 26, 2009 (See NRC Agency-wide Documents and Management Systems (ADAMS) ML092450113), and a Notice of Change of Control and Ownership Information package dated September 18, 2009 (See ADAMS ML092660641), all of which are available for public inspection, and can be copied for a fee, at the U.S. Nuclear Regulatory Commission's Public Document Room (PDR), located at One White Flint North, 11555 Rockville Pike (first floor), Rockville, Maryland 20852. The NRC ADAMS provides text and image files of NRC's public documents. These documents may be accessed through the NRC's Public Electronic Reading Room on the Internet at *http://www.nrc.gov.*

Persons who do not have access to ADAMS or who have problems in accessing the documents located in ADAMS may contact the PDR reference staff at 1–800–397–4209, 301–415–4737 or by e-mail at *pdr.resource@nrc.gov.* These documents may also be viewed electronically on the public computers located at the NRC's PDR, O1 F21, One White Flint North, 11555 Rockville Pike, Rockville, MD 20852. The PDR reproduction contractor will copy documents for a fee.

Dated at Rockville, Maryland, this 22nd day of October, 2009.

For the Nuclear Regulatory Commission.

Keith I. McConnell,

Deputy Director, Decommissioning and Uranium Recovery Licensing Directorate, Division of Waste Management and Environmental Protection, Office of Federal and State Materials and Environmental Management Programs.

[FR Doc. E9–26220 Filed 10–27–09; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[NRC–2009–0476]

Office of New Reactors; Interim Staff Guidance on Design Reliability Assurance Program; Section 17.4 of the Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants (NUREG–0800)

AGENCY: Nuclear Regulatory Commission (NRC).

ACTION: Solicitation of public comment.

SUMMARY: The NRC staff is soliciting public comment on its proposed Interim Staff Guidance (ISG) DC/COL–ISG–018 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML092290791). This ISG revises the guidance provided to the staff in Section 17.4, ''Reliability Assurance Program'' of NUREG–0800,

''Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants,'' March 2007 (SRP). This ISG revises the review responsibilities and further clarifies the acceptance criteria and evaluation findings contained in SRP Section 17.4 in support of the NRC reviews of the design certification (DC) and combined license (COL) applications. The NRC staff issues DC/COL–ISGs to facilitate timely implementation of current staff guidance and to facilitate activities associated with review of applications for DCs and COLs by the Office of New Reactors. The NRC staff intends to incorporate the final approved DC/COL–ISG–018 into the next revision of NUREG–0800, SRP Section 17.4 and Regulatory Guide (RG) 1.206, ''Combined License Applications for Nuclear Power Plants (LWR Edition),'' June 2007.

DATES: Comments must be filed no later than 30 days from the date of publication of this notice in the **Federal Register**. Comments received after this date will be considered, if it is practical to do so, but the Commission is able to ensure consideration only for comments received on or before this date.

ADDRESSES: You may submit comments by any one of the following methods. Please include Docket ID: NRC–2009–0476 in the subject line of your comments. Comments submitted in writing or in electronic form will be posted on the NRC Web site and on the Federal rulemaking Web site at *http://www.Regulations.gov*. Because your comments will not be edited to remove any identifying or contact information, the NRC cautions you against including any information in your submission that you do not want to be publicly disclosed.

The NRC requests that any party soliciting or aggregating comments received from other persons for submission to the NRC inform those persons that the NRC will not edit their comments to remove any identifying or contact information, and therefore, they should not include any information in their comments that they do not want publicly disclosed.

Federal Rulemaking Web site: Go to *http://www.Regulations.gov* and search for documents filed under Docket ID: NRC–2009–0476. Address questions about NRC dockets to Carol Gallagher at 301–492–3668; e-mail at *Carol.Gallagher@nrc.gov*.

Mail comments to: Michael T. Lesar, Chief, Rulemaking and Directives Branch (RDB), Division of Administrative Services, Office of Administration, *Mail Stop:* TWB–05–B01M, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, or by fax to RDB at (301) 492–3446.

The NRC ADAMS provides text and image files of NRC's public documents. These documents may be accessed through the NRC's Public Electronic Reading Room on the Internet at *http://www.nrc.gov/reading-rm/adams.html.* Persons who do not have access to ADAMS or who encounter problems in accessing the documents located in ADAMS should contact the NRC Public Document Room reference staff by telephone at 1–800–397–4209, 301–415–4737, or by e-mail at *pdr.resource@nrc.gov.*

FOR FURTHER INFORMATION CONTACT: Mr. Todd A. Hilsmeier, Project Manager, PRA Licensing Operations Support and Maintenance Branch 2, Division of Safety Systems and Risk Assessment, Office of New Reactors, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001; telephone 301–415–6788 or e-mail at *todd.hilsmeier@nrc.gov*.

SUPPLEMENTARY INFORMATION: The agency posts its issued staff guidance in the agency external Web page (*http://www.nrc.gov/reading-rm/doc-collections/isg/*).

The NRC staff is issuing this notice to solicit public comments on proposed DC/COL–ISG–018. After the NRC staff considers any public comments, it will make a determination regarding proposed DC/COL–ISG–018.

Dated at Rockville, Maryland, this 22nd day of October 2009.

For the Nuclear Regulatory Commission.

William F. Burton,

Branch Chief, Rulemaking and Guidance Development Branch, Division of New Reactor Licensing, Office of New Reactors.

[FR Doc. E9–26219 Filed 10–29–09; 8:45 am]

BILLING CODE 7590–01–P

RAILROAD RETIREMENT BOARD

Proposed Collection; Comment Request

SUMMARY: In accordance with the requirement of Section 3506 (c)(2)(A) of the Paperwork Reduction Act of 1995 which provides opportunity for public comment on new or revised data collections, the Railroad Retirement Board (RRB) will publish periodic summaries of proposed data collections.

Comments are invited on: (a) Whether the proposed information collection is necessary for the proper performance of the functions of the agency, including whether the information has practical utility; (b) the accuracy of the RRB's estimate of the burden of the collection of the information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; and (d) ways to minimize the burden related to the collection of information on respondents, including the use of automated collection techniques or other forms of information technology.

Title and purpose of information collection: Vocational Report; OMB 3220–0141. Section 2 of the Railroad Retirement Act (RRA) provides for payment of disability annuities to qualified employees and widow(ers). The establishment of permanent disability for work in the applicants ''regular occupation'' or for work in any regular employment is prescribed in 20 CFR 220.12 and 220.13 respectively.

The RRB utilizes Form G–251, *Vocational Report*, to obtain an applicant's work history. This information is used by the RRB to determine the effect of a disability on an applicant's ability to work. Form G–251 is designed for use with the RRB's disability benefit application forms and is provided to all applicants for employee disability annuities and to those applicants for a widow(er)'s disability annuity who indicate that they have been employed at some time.

Completion is required to obtain or retain a benefit. One response is requested of each respondent. The RRB proposes minor, non-burden impacting, editorial and clarifying changes to Form G–251. The completion time for Form G–251 is estimated at between 30 and 40 minutes per response. The RRB estimates that approximately 6,000 Form G–251's are completed annually.

Additional Information or Comments: To request more information or to obtain a copy of the information collection justification, forms, and/or supporting material, please call the RRB Clearance Officer at (312) 751–3363 or send an e-mail request to *Charles.Mierzwa@RRB.GOV*. Comments regarding the information collection should be addressed to Patricia A. Henaghan, Railroad Retirement Board, 844 North Rush Street, Chicago, Illinois 60611–2092 or send an e-mail to *Patricia.Henaghan@RRB.GOV*. Written comments should be received within 60 days of this notice.

Charles Mierzwa,

Clearance Officer.

[FR Doc. E9–26134 Filed 10–29–09; 8:45 am]

BILLING CODE 7905–01–P

SMALL BUSINESS ADMINISTRATION

Data Collection Available for Public Comments and Recommendations

ACTION: Notice and request for comments.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, this notice announces the Small Business Administration's intentions to request approval on a new and/or currently approved information collection.

DATES: Submit comments on or before December 29, 2009.

ADDRESSES: Send all comments regarding whether this information collection is necessary for the proper performance of the function of the agency, whether the burden estimates are accurate, and if there are ways to minimize the estimated burden and enhance the quality of the collection, to Cynthia Pitts, Director, Disaster Administrative Services, Small Business Administration, 409 3rd Street, 6th Floor, Washington, DC 20416.

FOR FURTHER INFORMATION CONTACT: Cynthia Pitts, Director, Disaster Administrative Services 202–205–7570 *cynthia.pitts@sba.gov*; Curtis B. Rich, Management Analyst, 202–205–7030 *curtis.rich@sba.gov.*

SUPPLEMENTARY INFORMATION: SBA is required to survey affected disaster areas within a state upon request by the Governor of that state to determine if there is sufficient change to warrant a disaster Declaration.

Title: ''Disaster Survey Worksheet.''

Description of Respondents: Applicants who warrant Disaster Declaration.

Form Number: 987.

Annual Responses: 2,640.

Annual Burden: 219.

Jacqueline White,

Chief, Administrative Information Branch.

[FR Doc. E9–26217 Filed 10–29–09; 8:45 am]

BILLING CODE P

SMALL BUSINESS ADMINISTRATION

[Disaster Declaration #11909 and #11910]

Tennessee Disaster #TN–00033

AGENCY: U.S. Small Business Administration.

ACTION: Notice.

SUMMARY: This is a notice of an Administrative declaration of a disaster for the State of Tennessee dated 10/21/2009.

Incident: Severe storms and flooding.

Incident Period: 09/16/2009.

Effective Date: 10/21/2009.

Physical Loan Application Deadline Date: 12/21/2009.

Economic Injury (EIDL) Loan Application Deadline Date: 07/21/2010.

ADDRESSES: Submit completed loan applications to: U.S. Small Business Administration, Processing And Disbursement Center, 14925 Kingsport Road, Fort Worth, TX 76155.

FOR FURTHER INFORMATION CONTACT: A. Escobar, Office of Disaster Assistance, U.S. Small Business Administration, 409 3rd Street, SW., Suite 6050, Washington, DC 20416.

SUPPLEMENTARY INFORMATION: Notice is hereby given that as a result of the Administrator's disaster declaration, applications for disaster loans may be filed at the address listed above or other locally announced locations.

The following areas have been determined to be adversely affected by the disaster:

Primary Counties: Hamilton

Contiguous Counties:

Tennessee: Bledsoe, Bradley, Marion, Meigs, Rhea, Sequatchie,

Georgia: Catoosa, Dade, Walker, Whitfield

The Interest Rates are:

	Percent
Homeowners With Credit Available Elsewhere	5.500
Homeowners Without Credit Available Elsewhere	2.750
Businesses With Credit Available Elsewhere	6.000
Businesses & Small Agricultural Cooperatives Without Credit Available Elsewhere	4.000
Other (Including Non-Profit Organizations) With Credit Available Elsewhere	4.500
Businesses And Non-Profit Organizations Without Credit Available Elsewhere	4.000

The number assigned to this disaster for physical damage is 11909 6 and for economic injury is 11910 0.

The States which received an EIDL Declaration # are Tennessee Georgia.

(Catalog of Federal Domestic Assistance Numbers 59002 and 59008)

Dated: October 21, 2009.

Karen G. Mills,

Administrator.

[FR Doc. E9–26182 Filed 10–29–09; 8:45 am]

BILLING CODE 8025–01–P

SMALL BUSINESS ADMINISTRATION

[Disaster Declaration #11913]

California Disaster #CA–00144 Declaration of Economic Injury

AGENCY: U.S. Small Business Administration.

ACTION: Notice.

SUMMARY: This is a notice of an Economic Injury Disaster Loan (EIDL) declaration for the State of California, dated 10/21/2009.

Incident: Modesto Office Complex Fire.

Incident Period: 08/02/2009.

Effective Date: 10/21/2009.

EIDL Loan Application Deadline Date: 07/21/2010.

ADDRESSES: Submit completed loan applications to: U.S. Small Business Administration, Processing And Disbursement Center, 14925 Kingsport Road, Fort Worth, TX 76155.

FOR FURTHER INFORMATION CONTACT: A. Escobar, Office of Disaster Assistance, U.S. Small Business Administration, 409 3rd Street, SW., Suite 6050, Washington, DC 20416.

SUPPLEMENTARY INFORMATION: Notice is hereby given that as a result of the Administrator's EIDL declaration, applications for economic injury disaster loans may be filed at the address listed above or other locally announced locations.

The following areas have been determined to be adversely affected by the disaster:

Primary Counties: Stanislaus

Contiguous Counties:

California: Alameda, Calaveras, Mariposa, Merced; San Joaquin, Santa Clara, Tuolumne

The Interest Rate is: 4.000.

The number assigned to this disaster for economic injury is 119130.

The State which received an EIDL Declaration # is California.

(Catalog of Federal Domestic Assistance Number 59002)

Dated: October 21, 2009.

Karen G. Mills,

Administrator.

[FR Doc. E9–26216 Filed 10–29–09; 8:45 am]

BILLING CODE 8025–01–P

OFFICE OF SCIENCE AND TECHNOLOGY POLICY

Nanomaterials and Human Health & Instrumentation, Metrology, and Analytical Methods Workshop: Public Meeting

ACTION: Notice of public meeting.

SUMMARY: The National Nanotechnology Coordination Office (NNCO), on behalf of the Nanoscale Science, Engineering, and Technology (NSET) Subcommittee of the Committee on Technology, National Science and Technology Council (NSTC), will hold a workshop on November 17–18, 2009, to provide an open forum to discuss the state-of-the-art of the science related to environmental, health, and safety aspects of nanomaterials in two areas: human health and instrumentation and metrology. Nanomaterials and Human Health & Instrumentation, Metrology, and Analytical Needs are two of the five environmental, health, and safety research categories identified in the NSET Subcommittee document *Strategy for Nanotechnology-Related Environmental, Health, and Safety Research* (*http://www.nano.gov/NNI_EHS_Research_Strategy.pdf*), which was released February 14, 2008.

DATES: The public meeting will be held on Tuesday, November 17, 2009 from 8:30 a.m. until 5 p.m. and on Wednesday, November 18, 2009 from 8:30 a.m. until 3:30 p.m.

ADDRESSES: The public meeting will be held at the Holiday Inn Rosslyn-Key Bridge, 1900 N. Fort Myer Drive, Arlington, VA 22209 (Metro stop: Rosslyn on the Orange and Blue lines). For directions, please see *www.holidayinn.com.*

Registration: Due to space limitations, pre-registration for the workshop is required. People interested in attending the workshop should register online at *http://nano.gov/html/meetings/humanhealth/register.html.* Written notices of participation by e-mail should be sent to *humanhealth@nnco.nano.gov.* Written notices also may be mailed to the Human Health & IMA Workshop, c/o NNCO, 4201 Wilson Blvd., Stafford II, Suite 405, Arlington, VA 22230. Registration is on a first-come, first-served basis. Registration will close on November 13, 2009 at noon EST.

Those interested in presenting 3–5 minutes of public comments at the meeting also should register at *http://nano.gov/html/meetings/humanhealth/register.html.* Written or electronic comments should be submitted by e-mail to *humanhealth@nnco.nano.gov* until December 1, 2009.

Information about the meeting, including the agenda, is posted at *http://www.nano.gov.*

The main sessions will be Web-cast. Please see *http://nano.gov/html/meetings/humanhealth/* for more information.

FOR FURTHER INFORMATION CONTACT: For information regarding this Notice, please contact Heather Evans or Liesl Heeter, National Nanotechnology Coordination Office. Telephone (703) 292–4533 or (703) 292–7916. *E-mail: humanhealth@nnco.nano.gov.*

SUPPLEMENTARY INFORMATION: Human Health and Instrumentation and Metrology research are used to guide efforts to improve environmental, health, and safety (EHS) protection with regard to nanoscale engineered materials and to monitor trends and progress. The purpose of this workshop is to engage in an active discussion and learn more about the state-of-the-art in (1) Nanomaterials and Human Health and (2) Instrumentation, Metrology, and Analytical Methods by discussing the state of the science to assess research progress, provide insight into gaps and barriers to progress, identify missing components, and suggest milestones to chart progress and next steps as input to the Federal Government's effort to adaptively manage its nanoEHS research strategy, and build dialogue and strengthen collaborations.

M. David Hodge,

OSTP, Operations Manager.

[FR Doc. E9–26263 Filed 10–29–09; 8:45 am]

BILLING CODE P

OFFICE OF SCIENCE AND TECHNOLOGY POLICY

Nanomaterials and the Environment & Instrumentation, Metrology, and Analytical Methods Workshop: Nanotechnology Primer Public Meeting

ACTION: Notice of public meeting.

SUMMARY: The National Nanotechnology Coordination Office (NNCO), on behalf of the Nanoscale Science, Engineering, and Technology (NSET) Subcommittee of the Committee on Technology, National Science and Technology Council (NSTC), will hold a public meeting on November 16, 2009, on nanotechnology research and development, including environmental, health, and safety concerns.

DATES: The Nanotechnology Primer public pre-meeting will be held on Monday November 16, 2009 from 7 p.m.–8:30 p.m. The purpose of this meeting is to provide general background material about nanotechnology and Federal nanotechnology research to participants.

ADDRESSES: The Nanotechnology Primer public meeting will be held at the Holiday Inn Rosslyn at Key Bridge, 1900 N. Fort Myer Drive, Arlington, VA 22209 (Metro stop: Rosslyn on the Orange and Blue lines). For directions, please see *http://www.holidayinn.com.*

Registration: Due to space limitations, pre-registration for the workshop is required. People interested in attending the workshop and/or the Nanotechnology Primer should register online at *http://www.nano.gov/html/meetings/humanhealth/register.html.* Written notices of participation by e-mail should be sent to *humanhealth@nnco.nano.gov.* Written notices may be mailed to the Environment & IMA Workshop, c/o NNCO, 4201 Wilson Blvd., Stafford II, Suite 405, Arlington, VA 22230. Registration is on a first-come, first-served basis. Registration will close on November 12, 2009 at 4 p.m. EST.

Information about the meeting, including the agenda, is posted at *http://www.nano.gov.*

FOR FURTHER INFORMATION CONTACT: For information regarding this Notice, please contact Liesl Heeter, telephone (703) 292–4533, or Heather Evans, telephone (703) 292–7916, National Nanotechnology Coordination Office. *E-mail: humanhealth@nnco.nano.gov.*

SUPPLEMENTARY INFORMATION: The Nanotechnology Primer pre-meeting is to provide general background material about nanotechnology and Federal nanotechnology research and development efforts to interested participants, particularly those attending the November 17–18, 2009 Nanomaterials and Human Health & Instrumentation, Metrology and Analytical Methods workshop. The November 17–18, 2009 workshop is to engage in an active discussion and learn more about the state-of-the-science in these two research areas. The November 16, 2009 Nanotechnology Primer public meeting is open to all interested parties on a space-available basis.

M. David Hodge,

OSTP, Operations Manager.

[FR Doc. E9–26264 Filed 10–29–09; 8:45 am]

BILLING CODE P

SECURITIES AND EXCHANGE COMMISSION

Submission for OMB Review; Comment Request

Upon Written Request, Copies Available From: Securities and Exchange Commission, Office of Investor Education and Advocacy, Washington, DC 20549–0213.

Extension:

Rule 12b–1; SEC File No. 270–188; OMB Control No. 3235–0212.

Notice is hereby given that, pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), the Securities and Exchange Commission (the ''Commission'') has submitted to the Office of Management and Budget a request for extension of the previously approved collection of information discussed below.

Rule 12b–1 (17 CFR 270.12b–1) permits a registered open-end investment company (''mutual fund'') to distribute its own shares and pay the expenses of distribution out of the mutual fund's assets provided, among other things, that the mutual fund adopts a written plan (''Rule 12b–1 plan'') and has in writing any agreements relating to the implementation of the Rule 12b–1 plan. The rule in part requires that (i) the adoption or material amendment of a Rule 12b–1 plan be approved by the mutual fund's directors and shareholders; (ii) the board review quarterly reports of amounts spent under the Rule 12b–1 plan; and (iii) the board consider continuation of the Rule 12b–1 plan at least annually. Rule 12b–1 also requires funds relying on the rule to preserve for six years, the first two years in an easily accessible place, copies of the Rule 12b–1 plan, related agreements and reports, as well as minutes of board meetings that describe the factors considered and the basis for adopting or continuing a Rule 12b–1 plan.

The board and shareholder approval requirements of Rule 12b–1 are designed to ensure that fund shareholders and directors receive adequate information to evaluate and approve a Rule 12b–1 plan. The requirement of quarterly reporting to the board is designed to ensure that the Rule 12b–1 plan continues to benefit the fund and its shareholders. The recordkeeping requirements of the rule are necessary to enable Commission staff to oversee compliance with the rule.

Based on information filed with the Commission by funds, Commission staff estimates that there are approximately 6,871 mutual fund portfolios have at least one share class subject to a Rule 12b–1 plan.[1] However, many of these portfolios are part of an affiliated group of funds known as a ''mutual fund family'' that is overseen by a common board of directors. Although the board must review and approve the Rule 12b–1 plan for each fund separately, we have allocated the costs and hourly burden related to Rule 12b–1 based on the number of fund families that have at least one fund that charges 12b–1 fees, rather than on the total number of mutual fund portfolios that individually have a 12b–1 plan.[2] Based on information filed with the Commission, the staff estimates that there are approximately 371 fund families with common boards of directors that have at least one fund with a 12b–1 plan.

Based on conversations with fund representatives, Commission staff estimates that for each of the 371 mutual fund families with a portfolio that has a Rule 12b–1 plan, the average annual burden of complying with the rule is 425 hours. This estimate takes into account the time needed to prepare quarterly reports to the board of directors, the board's consideration of those reports, and the board's annual consideration of whether to continue the plan.[3] We therefore estimate that the total hourly burden per year for all funds to comply with current information collection requirements under Rule 12b–1, is 157,675 hours (371 fund families × 425 hours per fund family = 157,675 hours) over the three year period for which we are requesting approval of the information collection burden).

If a currently operating fund seeks to (i) adopt a new Rule 12b–1 plan or (ii) materially increase the amount it spends for distribution under its Rule 12b–1 plan, Rule 12b–1 requires that the fund obtain shareholder approval. As a consequence, the fund will incur the cost of a proxy. Based on conversations with fund industry representatives, Commission staff estimates that approximately three funds per year prepare a proxy in connection with the adoption or material amendment of a Rule 12b–1 plan. The staff further estimates that the cost of each fund's proxy is $30,000. Thus the total annual cost burden of Rule 12b–1 to the fund industry is $90,000 (3 funds requiring a proxy × $30,000 per proxy).

[1] This estimate is based on information from the Commission's NSAR database.

[2] This allocation is based on conversations with fund representatives on how fund boards comply with the requirements of Rule 12b–1. Despite this allocation of hourly burdens and costs, the number of annual responses each year will continue to depend on the number of fund portfolios with 12b–1 plans rather than the number of fund families with 12b–1 plans. The staff estimates that the number of annual responses per fund portfolio will be four per year (quarterly, with the annual reviews taking place at one of the quarterly intervals). Thus, we estimate that funds will make 27,484 responses (6871 fund portfolios × 4 responses per fund portfolio= 27,484 responses) each year.

[3] We do not estimate any costs or time burden related to the recordkeeping requirement, as funds are already required to maintain these records pursuant to other rules, and would keep these records in any case as a matter of business practice.

The collections of information required by Rule 12b–1 are necessary to obtain the benefits of the rule. Notices to the Commission will not be kept confidential. 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.

Please direct general comments regarding the above information to the following persons: (i) Desk Officer for the Securities and Exchange Commission, Office of Management and Budget, Room 10102, New Executive Office Building, Washington, DC 20503 or send an e-mail to Shagufta Ahmed at *Shagufta_Ahmed@omb.eop.gov;* and (ii) Charles Boucher, Director/CIO, Securities and Exchange Commission, C/O Shirley Martinson, 6432 General Green Way, Alexandria, VA 22312; or send an e-mail to: *PRA_Mailbox@sec.gov.* Comments must be submitted to OMB within 30 days of this notice.

Dated: October 26, 2009.

Florence E. Harmon,

Deputy Secretary.

[FR Doc. E9–26175 Filed 10–29–09; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

Submission for OMB Review; Comment Request

Upon Written Request, Copies Available From: Securities and Exchange Commission, Office of Investor Education and Advocacy, Washington, DC 20549–0213.

Extension:

Rule 17f–6; SEC File No. 270–392; OMB Control No. 3235–0447.

Notice is hereby given that, under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520), the Securities and Exchange Commission (the ''Commission'') has submitted to the Office of Management and Budget a request for extension of the previously approved collection of information discussed below.

Rule 17f–6 (17 CFR 270.17f–6) under the Investment Company Act of 1940 (15 U.S.C. 80a) permits registered investment companies (''funds'') to maintain assets (*i.e.,* margin) with futures commission merchants (''FCMs'') in connection with commodity transactions effected on both domestic and foreign exchanges. Before the rule was adopted, funds generally were required to maintain such assets in special accounts with a custodian bank.[1]

The rule requires a written contract that contains certain provisions designed to ensure important safeguards and other benefits relating to the custody of fund assets by FCMs. To protect fund assets, the contract must require that FCMs comply with the segregation or secured amount requirements of the Commodity Exchange Act (''CEA'') and the rules under that statute. The contract also must contain a requirement that FCMs obtain an acknowledgment from any clearing organization that the fund's assets are held on behalf of the FCM's customers according to CEA provisions. Finally, FCMs are required to furnish to the Commission or its staff on request information concerning the fund's assets in order to facilitate Commission inspections.

The Commission estimates that approximately 2270 funds effect commodities transactions and could deposit margin with FCMs under Rule 17f–6 in connection with those transactions. Commission staff estimates that each fund uses and deposits margin with two different FCMs in connection with its commodity transactions.[2]

The Commission estimates that each of the 2270 funds spends an average of 1 hour annually complying with the contract requirements of the rule (*i.e.,* executing contracts that contain the requisite provisions with additional FCMs), for a total of 2270 burden hours. The estimate does not include the time required by an FCM to comply with the rule's contract requirements because, to the extent that complying with the contract provisions could be considered ''collections of information,'' the burden hours for compliance are already included in other PRA submissions or are de minimis.[3] The estimate of average burden hours is made solely for the purposes of the Paperwork Reduction Act, and is not derived from a comprehensive or even a representative survey or study of the costs of Commission rules and forms.

Compliance with the collection of information requirements of the rule is necessary to obtain the benefit of relying on the rule. If an FCM furnishes records pertaining to a fund's assets at the request of the Commission or its staff, the records will be kept confidential to the extent permitted by relevant statutory or regulatory provisions. The rule does not require these records be retained for any specific period of time. 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.

Please direct general comments regarding the above information to the following persons: (i) Desk Officer for the Securities and Exchange Commission, Office of Management and Budget, Room 10102, New Executive Office Building, Washington, DC 20503 or send an e-mail to Shagufta Ahmed at *Shagufta_Ahmed@omb.eop.gov;* and (ii) Charles Boucher, Director/CIO, Securities and Exchange Commission, C/O Shirley Martinson, 6432 General Green Way, Alexandria, VA 22312; or send an e-mail to: *PRA_Mailbox@sec.gov.* Comments must be submitted to OMB within 30 days of this notice.

Dated: October 26, 2009.

Florence E. Harmon,

Deputy Secretary.

[FR Doc. E9–26177 Filed 10–29–09; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

Submission for OMB Review; Comment Request

Upon Written Request Copies Available From: Securities and Exchange Commission, Office of Investor Education and Advocacy, Washington, DC 20549–0213.

Extension:

Form 1–E, Regulation E; SEC File No. 270–221; OMB Control No. 3235–0232.

Notice is hereby given that, pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), the Securities and Exchange Commission (the ''Commission'') has submitted to the Office of Management and Budget a request for extension of the previously approved collection of information discussed below.

Form 1–E (17 CFR 239.200) under the Securities Act of 1933 (15 U.S.C. 77a *et seq.*) (''Securities Act'') is the form that a small business investment company (''SBIC'') or business development company (''BDC'') uses to notify the Commission that it is claiming an exemption under Regulation E from registering its securities under the Securities Act. Rule 605 of Regulation E (17 CFR 230.605) under the Securities Act requires an SBIC or BDC claiming such an exemption to file an offering circular with the Commission that must also be provided to persons to whom an offer is made. Form 1–E requires an issuer to provide the names and addresses of the issuer, its affiliates, directors, officers, and counsel; a description of events which would make the exemption unavailable; the jurisdictions in which the issuer intends to offer the securities; information about unregistered securities issued or sold by the issuer within one year before filing the notification on Form 1–E; information as to whether the issuer is presently offering or contemplating offering any other securities; and exhibits, including copies of the rule 605 offering circular and any underwriting contracts.

The Commission uses the information provided in the notification on Form 1–E and the offering circular to determine whether an offering qualifies for the exemption under Regulation E. It is estimated that approximately six issuers file eight notifications, together with attached offering circulars, on Form 1–E with the Commission annually. The Commission estimates that the total burden hours for preparing these notifications would be 800 hours in the aggregate. Estimates of the burden hours are made solely for the purposes of the PRA, and are not derived from a comprehensive or even a representative survey or study of the costs of SEC rules and forms.

Compliance with the information collection requirements of the rules is necessary to obtain the benefit of relying on the rules. The information provided on Form 1–E and in the offering circular will not be kept confidential. 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.

Please direct general comments regarding the above information to the following persons: (i) Desk Officer for the Securities and Exchange Commission, Office of Management and Budget, Room 10102, New Executive Office Building, Washington, DC 20503 or send an e-mail to Shagufta Ahmed at

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[1] Custody of Investment Company Assets With Futures Commission Merchants and Commodity Clearing Organizations, Investment Company Act Release No. 22389 (Dec. 11, 1996) [61 FR 66207 (Dec. 17, 1996)].

[2] This estimate is based on information conversations with representatives of the fund industry.

[3] The rule requires a contract with the FCM to contain three provisions. Two of the provisions require the FCM to comply with existing requirements under the CEA and rules adopted under that Act. Thus, to the extent these provisions could be considered collections of information, the hours required for compliance would be included in the collection of information burden hours submitted by the Commodity Futures Trading Commission for its rules. The third contract provision requires that the FCM produce records or other information requested by the Commission or its staff. Commission staff has requested this type of information from an FCM so infrequently in the past that the annual burden hours are de minimis.

Shagufta_Ahmed@omb.eop.gov; and (ii) Charles Boucher, Director/CIO, Securities and Exchange Commission, C/O Shirley Martinson, 6432 General Green Way, Alexandria, VA 22312; or send an e-mail to: *PRA_Mailbox@sec.gov.* Comments must be submitted to OMB within 30 days of this notice.

Dated: October 26, 2009.

Florence E. Harmon,

Deputy Secretary.

[FR Doc. E9–26176 Filed 10–29–09; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

Sunshine Act Meeting

Notice is hereby given, pursuant to the provisions of the Government in the Sunshine Act, Public Law 94–409, that the Securities and Exchange Commission will hold a Closed Meeting on Tuesday, November 3, 2009 at 2 p.m.

Commissioners, Counsel to the Commissioners, the Secretary to the Commission, and recording secretaries will attend the Closed Meeting. Certain staff members who have an interest in the matters also may be present.

The General Counsel of the Commission, or his designee, has certified that, in his opinion, one or more of the exemptions set forth in 5 U.S.C. 552b(c)(3), (5), (7), (8), 9(B) and (10) and 17 CFR 200.402(a)(3), (5), (7), (8), 9(ii) and (10), permit consideration of the scheduled matters at the Closed Meeting.

Commissioner Casey, as duty officer, voted to consider the items listed for the Closed Meeting in a closed session.

The subject matter of the Closed Meeting scheduled for Tuesday, November 3, 2009 will be:

Institution and settlement of injunctive actions;

Institution and settlement of administrative proceedings;

An adjudicatory matter;

Regulatory matters regarding financial institutions; and

Other matters relating to enforcement proceedings.

At times, changes in Commission priorities require alterations in the scheduling of meeting items.

For further information and to ascertain what, if any, matters have been added, deleted or postponed, please contact:

The Office of the Secretary at (202) 551–5400.

Dated: October 27, 2009.

Elizabeth M. Murphy,

Secretary.

[FR Doc. E9–26256 Filed 10–28–09; 11:15 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

Sunshine Act Meeting

Notice is hereby given, pursuant to the provisions of the Government in the Sunshine Act, Public Law 94–409, that the Securities and Exchange Commission will hold an Open Meeting on November 2, 2009, at 10 a.m., in Room 10800, to hear oral argument on an appeal by Guy P. Riordan from an initial decision of an administrative law judge. The law judge found that, from around 1996 to December 2002, Riordan, a former registered representative associated with Wachovia Securities, LLC, in its Albuquerque, New Mexico, branch office, violated the antifraud provisions by making secret cash payments to the New Mexico State Treasurer in exchange for securities business from the Treasurer's Office. The law judge barred Riordan from associating with any broker or dealer; imposed a cease-and-desist order; ordered disgorgement of $1,017,278.78, plus prejudgment interest; and assessed a $500,000 third-tier civil penalty.

Among the issues likely to be argued are whether Riordan engaged in the conduct alleged, whether that conduct constituted securities fraud and, if so, the extent to which sanctions should be imposed.

Commissioner Casey, as duty officer, determined that no earlier notice thereof was possible.

At times, changes in Commission priorities require alterations in the scheduling of meeting items.

For further information and to ascertain what, if any, matters have been added, deleted or postponed, please contact:

The Office of the Secretary at (202) 551–5400.

Dated: October 28, 2009.

Elizabeth M. Murphy,

Secretary.

[FR Doc. E9–26257 Filed 10–28–09; 4:15 pm]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–60876; File No. SR–NYSEArca–2009–93]

Self-Regulatory Organizations; NYSE Arca, Inc., Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Add 75 Options Classes to the Penny Pilot Program

October 26, 2009.

Pursuant to Section 19(b)(1) [1] of the Securities Exchange Act of 1934 (the ''Act''),[2] and Rule 19b–4 thereunder,[3] notice is hereby given that, on October 21, 2009, NYSE Arca, Inc. (''NYSE Arca'' or the ''Exchange'') filed with the Securities and Exchange Commission (the ''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been prepared by the self-regulatory organization. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to designate 75 options classes to be added to the Penny Pilot Program for Options (''Penny Pilot'' or ''Pilot'') on November 2, 2009. The text of the proposed rule change is attached as Exhibit 5 to the 19b–4 form [sic].[4] A copy of this filing is available on the Exchange's Web site at [sic], at the Exchange's principal office and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the self-regulatory organization included statements concerning the purpose of, and basis for, the proposed rule change and discussed any comments it received on the proposed rule change. The text of those statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in Sections A, B, and C below, of the most significant parts of such statements.

[1] 15 U.S.C. 78s(b)(1).

[2] 15 U.S.C. 78a.

[3] 17 CFR 240.19b–4.

[4] The Commission notes that no rule text was attached as an exhibit to this filing and there are no changes to the rule text proposed by the Exchange.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

NYSE Arca proposes to identify the next 75 options classes to be added to the Penny Pilot effective November 2, 2009. The Exchange recently received approval to extend and expand the Pilot through December 31, 2010.[5] In that filing, the Exchange had proposed expanding the Pilot on a quarterly basis to add the next 75 most actively traded multiply listed options classes based on national average daily volume for the six months prior to selection, closing under $200 per share on the Expiration Friday prior to expansion, except that the month immediately preceding their addition to the Penny Pilot will not be used for the purpose of the six month analysis.[6]

NYSE Arca proposes adding the following 75 options classes to the Penny Pilot on November 2, 2009, based on national average daily volume from April 1, 2009 through September 30, 2009:

Nat'l ranking	Symbol	Company name
118	ABX	Barrick Gold Corp.
48	AXP	American Express Co.
134	AUY	Yamana Gold Inc.
93	BA	Boeing Co/The.
115	BBT	BB&T Corp.
111	BBY	Best Buy Co Inc.
94	BP	BP PLC.
67	CHK	Chesapeake Energy Corp.
58	CIT	CIT Group Inc.
78	COF	Capital One Financial Corp.
68	CVX	Chevron Corp.
130	DE	Deere & Co.
104	DOW	Dow Chemical Co/The.
49	DRYS	DryShips Inc.
88	EFA	iShares MSCI EAFE Index Fund.
64	ETFC	E*Trade Financial Corp.
32	EWZ	iShares MSCI Brazil Index Fund.
25	FAS	Direxion Daily Financial Bull. 3X Shares.
33	FAZ	Direxion Daily Financial Bear. 3X Shares.
112	FITB	Fifth Third Bancorp.
70	FSLR	First Solar Inc.
26	FXI	iShares FTSE/Xinhua China 25 Index Fund.
82	GDX	Market Vectors—Gold Miners ETF.
127	GG	Goldcorp Inc.
18	GLD	SPDR Gold Trust.
129	HGSI	Human Genome Sciences Inc.
62	HIG	Hartford Financial Services Group Inc.
72	HPQ	Hewlett-Packard Co.
59	IBM	International Business Machines Corp.
45	IYR	iShares Dow Jones US Real Estate Index Fund.
105	JNJ	Johnson & Johnson.
131	JNPR	Juniper Networks Inc.
98	KO	Coca-Cola Co/The.
39	LVS	Las Vegas Sands Corp.
87	MCD	McDonald's Corp.
71	MGM	MGM Mirage.
113	MON	Monsanto Co.
63	MOS	Mosaic Co/The.
120	MRK	Merck & Co Inc/NJ.
35	MS	Morgan Stanley.
73	NLY	Annaly Capital Management Inc.
99	NOK	Nokia OYJ.
121	NVDA	Nvidia Corp.
80	ORCL	Oracle Corp.
61	PALM	Palm Inc.
37	PBR	Petroleo Brasileiro SA.
85	PG	Procter & Gamble Co/The.
41	POT	Potash Corp of Saskatchewan Inc.
74	RF	Regions Financial Corp.
124	RIG	Transocean Ltd.
132	RMBS	Rambus Inc.
103	S	Sprint Nextel Corp.
83	SDS	ProShares UltraShort S&P500.
122	SKF	ProShares UltraShort Financials.
107	SLB	Schlumberger Ltd.
91	SLV	iShares Silver Trust.
84	SRS	ProShares UltraShort Real Estate.
119	SSO	ProShares Ultra S&P500.

[5] *See* Exchange Act Release No. 60711 (September 23, 2009), 74 FR 49419 (September 28, 2009) (order approving SR–NYSEArca-2009–44).

[6] Index products would be included in the expansion if the underlying index level was under 200.

Nat'l ranking	Symbol	Company name
101	STI	SunTrust Banks Inc.
125	SVNT	Savient Pharmaceuticals Inc.
92	TBT	ProShares UltraShort 20+ Year Treasury.
14	UNG	United States Natural Gas Fund LP.
117	UNH	UnitedHealth Group Inc.
110	UPS	United Parcel Service Inc.
81	USB	US Bancorp.
44	USO	United States Oil Fund LP.
60	UYG	ProShares Ultra Financials.
96	V	Visa Inc.
10	WFC	Wells Fargo & Co.
133	WYNN	Wynn Resorts Ltd.
52	X	United States Steel Corp.
114	XHB	SPDR S&P Homebuilders ETF.
86	XLI	Industrial Select Sector SPDR Fund.
79	XLU	Utilities Select Sector SPDR Fund.
54	XRT	SPDR S&P Retail ETF.

2. Statutory Basis

The Exchange believes the proposed rule change is consistent with and furthers the objectives of Section 6(b)(5) of the Act, in that it is designed to promote just and equitable principles of trade, remove impediments to and perfect the mechanism of a free and open market and a national market system and, in general, to protect investors and the public interest, by identifying the options classes to be added to the Pilot in a manner consistent with prior approvals and filings.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were solicited or received with respect to the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The proposed rule change is effective upon filing pursuant to Section 19(b)(3)(A)(i) [7] of the Act and Rule 19b–4(f)(1) [8] thereunder, in that it constitutes a stated policy, practice, or interpretation with respect to the meaning, administration, or enforcement of an existing rule of the Exchange.

At any time within 60 days of the filing of the proposed rule change, the Commission may summarily abrogate 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.[9]

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 e-mail to *rule-comments@sec.gov.* Please include File Number SR–NYSEArca–2009–93 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–2009–93. This file number should be included on the subject line if e-mail 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 inspection and copying in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549–1090 on official business days between the hours of 10 a.m. and 3 p.m. Copies of the filing also will be available for inspection and copying at NYSE Arca's principal office and on its Internet Web site at [sic]. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–NYSEArca–2009–93 and should be submitted on or before November 20, 2009.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[10]

Florence E. Harmon,

Deputy Secretary.

[FR Doc. E9–26171 Filed 10–29–09; 8:45 am]

BILLING CODE 8011–01–P

[7] 15 U.S.C. 78s(b)(3)(A)(i).

[8] 17 CFR 240.19b–4(f)(1).

[9] *See* 15 U.S.C. 78s(b)(3)(C).

[10] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–60879; File No. SR–Phlx–2009–90]

Self-Regulatory Organizations; NASDAQ OMX PHLX, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Permit Listing Option Series That Are Restricted to Closing Transactions if Such Series Are Listed and Restricted to Closing Transactions on Another National Securities Exchange

October 26, 2009.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 [2] thereunder, notice is hereby given that on October 16, 2009, NASDAQ OMX PHLX, Inc. (''Phlx'' or ''Exchange'') 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 the Exchange. Phlx filed the proposal as a ''non-controversial'' proposed rule change pursuant to Section 19(b)(3)(A)(iii) of the Act [3] and Rule 19b–4(f)(6) thereunder.[4] 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 is filing with the Commission a proposal to amend Phlx Rule 1010 (Withdrawal of Approval of Underlying Securities or Options) to permit the Exchange to list option series that are restricted to closing transactions if such series are listed and restricted to closing transactions on another exchange; and to add an exception regarding opening transactions to accommodate or facilitate certain closing transactions. The Exchange requests that the Commission waive the 30-day operative delay period contained in Exchange Act Rule 19b–4(f)(6)(iii).[5]

The text of the proposed rule change is available on the Exchange's Web site at *http://nasdaqomxphlx.cchwallstreet.com/NASDAQOMXPHLX/Filings/,* at the principal office of the Exchange, and at the Commission's Public Reference Room.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] 15 U.S.C. 78s(b)(3)(A)(iii).

[4] 17 CFR 240.19b–4(f)(6).

[5] 17 CFR 240.19b–4(f)(6)(iii).

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The purpose of the proposed rule change is to amend Phlx Rule 1010 to permit the Exchange to list option series that are restricted to closing transactions if such series are listed and restricted to closing transactions on another exchange; and to add an exception regarding opening transactions to accommodate or facilitate certain closing transactions.

This filing is based on a similar immediately effective filing recently filed by another options exchange, Chicago Board Options Exchange (''CBOE'').[6] In that filing, it was noted that the impetus for the filing was a customer request for it to list a series of options that was previously delisted by the filing exchange but was listed on another exchange and restricted to closing transactions, a situation that may equally occur on Phlx as well as other options exchanges.

Rule 1009 (Criteria for Underlying Securities) sets forth the requirements or criteria that underlying securities must meet before the Exchange may initially list options on such securities. Rule 1010 sets forth listing maintenance and delisting criteria in respect of securities underlying options listed on the Exchange that are used by the Exchange to determine whether such listing status should be continued. These rules do not have provisions for listing option series that are restricted to closing transactions where such series are listed on another exchange.

Phlx proposes to add new Commentary .05 to Rule 1010 to provide that if an option series is listed but restricted to closing transactions on another national securities exchange, the Exchange may list such series (even if such series would not otherwise be eligible for listing under the Exchange's rules), which shall also be restricted to closing transactions on the Exchange.[7]

Similar to series that no longer meet the Exchange's criteria for continued listing, (i) Opening transactions by market makers [8] executed to accommodate closing transactions of other market participants, and (ii) opening transactions by Phlx member organizations to facilitate the closing transactions of public customers executed as crosses pursuant to and in accordance with Phlx Rule 1064 (b) will be permitted in any restricted series listed pursuant to proposed Commentary .05 to Rule 1010. No restrictions will be in place with respect to the exercise of any restricted series.

Additionally, the Exchange is making changes in Rule 1010 to codify exceptions for these opening transactions by market makers to accommodate closing transactions of other market participants or by member organizations to facilitate the closing transactions of public customers executed as crosses. This is done to conform Rule 1010 to similar provisions in listing rules of other options exchanges.[9]

The Exchange believes that the proposed rule change should encourage competition and be beneficial to traders and market participants by providing them with a means to trade on the Exchange securities that are listed and traded on other exchanges.

2. Statutory Basis

The Exchange believes that its proposal is consistent with Section 6(b) of the Act [10] in general, and furthers the objectives of Section 6(b)(5) of the Act [11] in particular, in that it is designed to promote just and equitable principles of trade, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general to protect

[6] *See* Securities Exchange Act Release No. 60625 (September 4, 2009), 74 FR 46825 (September 11, 2009) (SR–CBOE–2009–066) (notice of filing and immediate effectiveness).

[7] The parenthetical text is being proposed to eliminate ambiguity about the Exchange's ability to list a restricted series pursuant to proposed Commentary .05 to Rule 1010 in the event other Exchange Rules would otherwise prohibit the listing of that series.

[8] Market makers on the Exchange include specialists, Registered Options Traders (''ROTs''), Streaming Quote Traders (''SQTs''), and Remote Streaming Quote Traders (''RSQTs''). *See* Rule 1014(b).

[9] *See, for example,* CBOE Rule 5.4 and Securities Exchange Act Release No. 48142 (July 9, 2003), 68 FR 42150 (July 16, 2003) (SR–CBOE–2002–36) (order approving, among other things, exceptions for certain opening transactions by market makers).

[10] 15 U.S.C. 78f(b).

[11] 15 U.S.C. 78f(b)(5).

investors and the public interest. Permitting the Exchange to accommodate possible customer requests and allow execution of trades on the Exchange will encourage competition and not harm investors or the public interest.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change has become effective pursuant to Section 19(b)(3)(A) of the Act [12] and Rule 19b–4(f)(6) [13] thereunder because the proposal does not: (i) Significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) by its terms, become operative for 30 days from the date on which it was filed, or such shorter time as the Commission may designate if consistent with the protection of investors and the public interest, provided that the Exchange has given the Commission 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.[14]

A proposed rule change filed under Rule 19b–4(f)(6) normally may not become operative prior to 30 days after the date of filing. However, Rule 19b–4(f)(6)(iii) [15] permits the Commission to designate a shorter time if such action is consistent with the protection of investors and the public interest. The Exchange has requested that the Commission waive the 30-day operative delay period. The Commission believes that waiver of the 30-day operative delay is consistent with the protection of investors and the public interest. In particular, the Exchange would be permitted to list the restricted series solely for the purpose of closing transactions as long as the restricted series is listed on another national securities exchange. In addition, the proposed rule change is substantially similar to the rules of CBOE.[16] The Commission therefore designates the proposal operative upon filing.[17]

At any time within 60 days of the filing of the proposed rule change, the Commission may summarily abrogate such proposed 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.[18]

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 e-mail to *rule-comments@sec.gov.* Please include File Number SR–Phlx–2009–90 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–2009–90. This file number should be included on the subject line if e-mail 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 inspection and copying in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of such filing also will be available for inspection and copying at the principal office of 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–2009–90 and should be submitted on or before November 20, 2009.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[19]

Florence E. Harmon,

Deputy Secretary.

[FR Doc. E9–26173 Filed 10–29–09; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–60881; File No. SR–OCC–2009–16]

Self-Regulatory Organizations; The Options Clearing Corporation; Notice of Filing and Immediate Effectiveness of Proposed Rule Change relating to Its Market Loan Program To Allow Dividend Equivalent Payments To Be Principally Effected Through The Depository Trust Company's Facilities

October 26, 2009.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 ("Act"),[1] notice is hereby given that on September 28, 2009, The Options Clearing Corporation ("OCC") filed with the Securities and Exchange Commission ("Commission") the proposed rule change described in Items I, II, and III below, which items have been prepared primarily by OCC. OCC filed the proposal pursuant to Section 19(b)(3)(A)(iii) of the Act [2] and Rule 19b–4(f)(4) [3] thereunder so that the proposal was effective upon filing with the Commission. The Commission is publishing this notice to solicit comments on the rule change from interested parties.

[12] 15 U.S.C. 78s(b)(3)(A).

[13] 17 CFR 240.19b–4(f)(6).

[14] Phlx has satisfied this requirement.

[15] 17 CFR 240.19b–4(f)(6)(iii).

[16] *See* CBOE Rules 5.4 and 5.4.12(b).

[17] For purposes only of waiving the operative delay for this proposal, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

[18] 15 U.S.C. 78s(b)(3)(C).

[19] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 15 U.S.C. 78s(b)(3)(A)(iii).

[3] 17 CFR 240.19b–4(f)(4).

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The proposed rule change would amend OCC's rules relating to its Market Loan Program to allow Dividend Equivalent Payments to be principally effected through The Depository Trust Company's (''DTC'') facilities.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, OCC 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. OCC has prepared summaries, set forth in sections (A), (B), and (C) below, of the most significant aspects of these statements.[4]

(A) Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

With respect to a stock loan effected under OCC's Market Loan Program (''Market Loan''), OCC guarantees payments in lieu of cash dividends and distributions (''Dividend Equivalent Payments'') that a lending clearing member is entitled to receive with respect to the loaned stock during the term of such Market Loan. OCC's guaranty is limited to the amount for which OCC has collected margin from the responsible borrowing clearing member prior to the expected payment date. Until now, OCC has effected collections and payments of Dividend Equivalent Payments between the relevant clearing members through its daily cash settlement system. However, clearing members participating in the Market Loan Program are now requesting that Dividend Equivalent Payments be made through DTC's Automatic Dividend Tracking Services (''Dividend Service''). In order to accommodate such request, OCC proposes to amend its Rules as described below.

OCC proposes to amend paragraph (a)(ii) of Rule 2206A so that Dividend Equivalent Payments would be effected through DTC's facilities on each payment date by transfers from and to the relevant clearing members with such transfers flowing through OCC's account at DTC in order to maintain anonymity between lenders and borrowers.[5] In order to provide reasonable assurance that there would not be any net settlement obligations against OCC's account at the end of any day, OCC is reserving the authority to remove a Market Loan from the Dividend Service and is reserving the authority to make null and void any obligation to effect such payments through DTC's facilities. Once such authority is exercised, Dividend Equivalent Payments for such Market Loans would no longer be settled through DTC's facilities. Instead, they would be settled through OCC's cash settlement system on the next business day to the extent that, as described above, OCC had already collected sufficient margin from the responsible borrowing clearing member. The new procedure for processing Dividend Equivalent Payments will be applied to Market Loans effected on and after October 2, 2009.

Although OCC will no longer serve as the primary channel through which collections and payments of Dividend Equivalent Payments are made, OCC will continue to collect margin with respect to such Dividend Equivalent Payments based on calculations provided by a loan market. Futhermore, OCC will continue to have no liability to a clearing member for errors in a loan market's calculations. Accordingly, OCC also proposes to amend Paragraph (a)(ii) of Rule 2206A to provide clarification with respect to such calculations and OCC's liability.

The proposed rule change is consistent with Section 17A of the Act,[6] as amended, because it will streamline the processing of Dividend Equivalent Payments thereby promoting the prompt and accurate clearance and settlement of securities lending transactions.

(B) Self-Regulatory Organization's Statement on Burden on Competition

OCC does not believe that the proposed rule change will have any impact or impose any burden on competition.

(C) Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

Written comments relating to the proposed rule change were not and are not intended to be solicited or received. OCC will notify the Commission of any written comments received by OCC.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing proposed rule change has become effective upon filing pursuant to Section 19(b)(3)(A)(iii) of the Act[7] and Rule 19b–4(f)(4)[8] thereunder because the proposed rule change effects a change in an existing service of OCC that: (i) Does not adversely affect the safeguarding of securities or funds in the custody or control of OCC or for which it is responsible and (ii) does not significantly affect the respective rights or obligations of OCC or persons using the service. At any time within sixty days of the filing of the proposed rule change, the Commission may summarily abrogate such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov.* Please include File Number SR–OCC–2009–16 on the subject line.

Paper Comments

- Send paper comments in triplicate to Secretary, Elizabeth M. Murphy, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–OCC–2009–16. This file number should be included on the subject line if e-mail 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

[4] The Commission has modified the text of the summaries prepared by OCC.

[5] Preserving anonymity between lenders and borrowers is important to the operation of the Market Loan Program because the Market Loan Program is intended to provide a framework within which securities lending transactions will be executed, mostly on an anonymous basis, through electronic trading systems.

[6] 15 U.S.C. 78q–1.

[7] 15 U.S.C. 78s(b)(3)(A)(iii).

[8] 17 CFR 240.19b–4(f)(4).

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 inspection and copying in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of such filings also will be available for inspection and copying at the principal office of OCC and on OCC's Web site at *http://www.theocc.com/publications/rules/proposed_changes/sr_occ_09_16.pdf.* 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–OCC–2009–16 and should be submitted on or before November 20, 2009

For the Commission by the Division of Trading and Markets, pursuant to delegated authority.[9]

Florence E. Harmon,

Deputy Secretary.

[FR Doc. E9–26174 Filed 10–29–09; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–60877; File No. SR–Phlx–2009–92]

Self-Regulatory Organizations; NASDAQ OMX PHLX, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to the TOPO Plus Orders Data Feed

October 26, 2009.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 [2] thereunder, notice is hereby given that on October 21, 2009, NASDAQ OMX PHLX, Inc. (''Phlx'' or ''Exchange'') 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 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 make available without charge a direct data product related to the trading of standardized options on the Exchange's enhanced electronic trading platform for options, Phlx XL II.[3] Specifically, the Exchange is proposing to establish and deploy a direct data feed product called Top of Phlx Options Plus Orders (''TOPO Plus Orders''), which will include disseminated Exchange top-of-market data (including orders, quotes and trades), together with all information that is included in the Exchange's Specialized Order Feed (''SOF'') as described more fully below.

The text of the proposed rule change is available on the Exchange's Web site at *http://www.nasdaqtrader.com/micro.aspx?id=PHLXRulefilings*, at the principal office of the Exchange, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The purpose of the proposed rule change is to make available without charge the TOPO Plus Orders data feed.

On June 5, 2009, the Exchange launched the Phlx XL II system, which was subject to a symbol-by-symbol rollout schedule that was completed on July 23, 2009 (the ''rollout''). Currently, all options listed on the Exchange are traded on Phlx XL II. In conjunction with the launch and rollout of the Phlx XL II system, the Exchange developed the Top of Phlx Options data feed (''TOPO'') [4] which provides to subscribers a direct data feed that includes the Exchange's best bid and offer position, with aggregate size, based on displayable order and quoting interest on the Phlx XL II system. The data contained in the TOPO data feed is identical to the data sent to the processor for the Options Price Regulatory Authority (''OPRA''), and the TOPO and OPRA data leave the Phlx XL II system at the same time.

In conjunction with the deployment of Phlx XL II, the Exchange represented that, within 90 days following the completion of the rollout,[5] it will offer a data feed (TOPO Plus Orders) to all market participants, which would include disseminated Exchange top-of-market data (including orders, quotes and trades) and all information that is included in SOF.

The SOF provides to its users real-time information to keep track of the single order book(s), single and complex orders, complex strategy and Live Auction for all symbols for which the user is configured. Users may be configured for one or more symbols. SOF provides real-time data for the entire book to its users. It is a compilation of limit order data resident in the Exchange's limit order book for options traded on the Exchange that the Exchange provides through a real-time data feed. The Exchange updates SOF information upon receipt of each displayed limit order. For every limit price, the SOF includes the aggregate order volume.

TOPO Plus Orders responds to the desire of some market participants for depth-of-book data. TOPO Plus Orders will provide top of book data to its users, together with the same data provided to SOF users. The Exchange represents that it will send this data to TOPO Plus Orders users no later than it will send such data to SOF users, and that it will make the data feed available to any market participant that wishes to subscribe to it.

The Exchange anticipates that it will eventually phase out SOF and make available TOPO to users that want only top of book data, and TOPO Plus Orders to users that want both top of book data and the real-time full limit order book data feed.

Initially, the Exchange will not charge fees for TOPO Plus. The Exchange contemplates that it will propose to charge fees for the use of TOPO Plus Orders. The Exchange will submit a

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[9] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 59995 (May 28, 2009), 74 FR 26750 (June 3, 2009) (SR–Phlx–2009–32).

[4] *See* Securities Exchange Act Release No. 60459 (August 7, 2009), 74 FR 41466 (August 17, 2009) (SR–Phlx–2009–54).

[5] Specifically, by October 21, 2009.

proposed rule change to the Commission in order to implement those fees.

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with the provisions of Section 6 of the Act,[6] in general and, because there will be no initial fees charged, with Section 6(b)(4) of the Act,[7] in particular, in that it provides for the equitable allocation of reasonable dues, fees and other charges among members and issuers and other persons using any facility or system which Phlx operates or controls.

The Exchange believes that the proposed rule change is also consistent with the provisions of Section 6(b)(5) of the Act,[8] in that it is designed to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in regulating, clearing, settling, processing information with respect to, and facilitating transactions in securities, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general, to protect investors and the public interest; and is not designed to permit unfair discrimination between customers, issuers, brokers, or dealers, or to regulate by virtue of any authority conferred by the Act matters not related to the purposes of the Act the administration of the Exchange. Specifically, the proposal is not designed to permit unfair discrimination among participants because it provides a mechanism for all market participants to obtain data that was previously available only to SOF users.

The Exchange further believes that the proposed rule change is also consistent with Section 6(b)(8) of the Act [9] in that it does not impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act.

The Exchange believes that this proposal is in keeping with all of these principles by facilitating investors' prompt access to Exchange limit order book information and providing increased transparency. Additionally, this proposal provides market participants with supplemental market information concerning orders on the Exchange's limit order book, which supports the system of a free and open market.

[6] 15 U.S.C. 78f.

[7] 15 U.S.C. 78f(b)(4).

[8] 15 U.S.C. 78f(b)(5).

[9] 15 U.S.C. 78f(b)(8).

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

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 after the date of the filing, or such shorter time as the Commission may designate, it has become effective pursuant to Section 19(b)(3)(A) of the Act [10] and Rule 19b–4(f)(6) [11] thereunder.

A proposed rule change filed under Rule 19b–4(f)(6) [12] normally does not become operative for 30 days after the date of filing. However, Rule 19b–4(f)(6)(iii) [13] permits the Commission to designate a shorter time if such action is consistent with the protection of investors and the public interest. The Exchange requests that the Commission waive the 30-day operative delay so that the proposal may become operative immediately upon filing. The Exchange believes that such a waiver will address the importance of increasing the Exchange's transparency by providing the TOPO Plus Orders data feed to market participants, and ensure that the Exchange will meet its obligation to deploy TOPO Plus Orders by October 21, 2009.

The Commission believes waiving the 30-day operative delay is consistent with the protection of investors and the public interest because such waiver will allow the Exchange to immediately provide increased transparency to market participants without charge by providing limit order data resident in the Exchange's limit order book to all market participants, rather than just to those participants eligible to receive data through SOF. Further, waiver of the operative delay will allow the Exchange to meet its obligation to make such data available to all market participants by October 21, 2009. Accordingly, the Commission designates the proposed rule change operative upon filing with the Commission.[14]

At any time within 60 days of the filing of the proposed rule change, the Commission may summarily abrogate 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.

[10] 15 U.S.C. 78s(b)(3)(A).

[11] 17 CFR 240.19b–4(f)(6). In addition, Rule 19b–4(f)(6) requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change 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. Phlx has satisfied this requirement.

[12] 17 CFR 240.19b–4(f)(6).

[13] 17 CFR 240.19b–4(f)(6)(iii).

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 e-mail to *rule-comments@sec.gov.* Please include File Number SR–Phlx–2009–92 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–2009–92. This file number should be included on the subject line if e-mail 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

[14] For purposes only of waiving the 30-day operative delay of this proposal, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. 15 U.S.C. 78c(f).

available for inspection and copying in the Commission's Public Reference Room, on official business days between the hours of 10 a.m. and 3 p.m. Copies of such filing also will be available for inspection and copying at the principal office of 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–2009–92 and should be submitted on or before November 20, 2009.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[15]

Florence E. Harmon,

Deputy Secretary.

[FR Doc. E9–26172 Filed 10–29–09; 8:45 am]

BILLING CODE 8011–01–P

DEPARTMENT OF TRANSPORTATION

Federal Railroad Administration

Petition for Waiver of Compliance

In accordance with Part 211 of Title 49 Code of Federal Regulations (CFR), notice is hereby given that the Federal Railroad Administration (FRA) has received a request for a waiver of compliance from certain requirements of its safety standards. The individual petition is described below, including the party seeking relief, the regulatory provisions involved, the nature of the relief being requested, and the petitioner's arguments in favor of relief.

The National Railroad Passenger Corporation

[Docket Number FRA–2009–0103]

The National Railroad Passenger Corporation (Amtrak), a Class 1 Railroad, petitioned FRA for a waiver of compliance from certain provisions prescribed by 49 CFR 214.335 *On-track safety procedures for roadway work groups.*

49 CFR 214.7 *Definitions,* states in part, ''Fouling a track means the placement of an individual or an item of equipment in such proximity to a track that the individual or equipment could be struck by a moving train or on-track equipment, or in any case is within four feet of the field side of the near running rail.'' The requirements in 49 CFR 214.335 specify the methods in which roadway work groups are provided on-track safety in order to foul railroad tracks to perform work. Those methods include working limits and train approach warning.

Amtrak states that the current definition of fouling a track prevents the timely removal of snow from the last 3 feet of station platforms adjacent to the track and it discourages the removal of snow in an area where snow removal is critical for passenger safety.

This waiver request is submitted for the removal of snow on platforms exclusively on passenger station platforms outside of the Northeast Corridor. The method proposed would use train conductors to coordinate railroad employees or contractors to remove snow at the platforms after they have received documented training on the process which includes:

1. Job briefings to discuss work to be done.
2. Not crossing the yellow tactile strip.
3. Directions on which tools to use.
4. Not working while trains are moving.

Interested parties are invited to participate in these proceedings by submitting written views, data, or comments. FRA does not anticipate scheduling a public hearing in connection with these proceedings since the facts do not appear to warrant a hearing. If any interested party desires an opportunity for oral comment, they should notify FRA, in writing, before the end of the comment period and specify the basis for their request.

All communications concerning these proceedings should identify the appropriate docket number (*e.g.,* Waiver Petition Docket Number FRA–2009–0103) and may be submitted by any of the following methods:

- *Web site: http://www.regulations.gov.* Follow the online instructions for submitting comments.
- *Fax:* 202–493–2251.
- *Mail:* Docket Operations Facility, U.S. Department of Transportation, 1200 New Jersey Avenue, SE., W12–140, Washington, DC 20590.
- *Hand Delivery:* 1200 New Jersey Avenue, SE., Room W12–140, Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Communications received within 45 days of the date of this notice will be considered by FRA before final action is taken. Comments received after that date will be considered as far as practicable. All written communications concerning these proceedings are available for examination during regular business hours (9 a.m.–5 p.m.) at the above facility. All documents in the public docket are also available for inspection and copying on the Internet at the docket facility's Web site at *http://www.regulations.gov.*

Anyone is able to search the electronic form of any written communications and comments received into any of our dockets by the name of the individual submitting the document (or signing the document, 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) or at *http://www.dot.gov/privacy.html.*

Issued in Washington, DC, on October 26, 2009.

Grady C. Cothen, Jr.,

Deputy Associate Administrator for Safety Standards and Program Development.

[FR Doc. E9–26214 Filed 10–29–09; 8:45 am]

BILLING CODE 4910–06–P

DEPARTMENT OF THE TREASURY

Submission for OMB Review; Comment Request

October 23, 2009.

The Department of the Treasury will submit the following public information collection requirement(s) to OMB for review and clearance under the Paperwork Reduction Act of 1995, Public Law 104–13 on or after the publication date of this notice. Copies of the submission(s) may be obtained by calling the Treasury Bureau Clearance Officer listed. Comments regarding this information collection should be addressed to the OMB reviewer listed and to the Treasury Department Clearance Officer, Department of the Treasury, Room 11000, 1750 Pennsylvania Avenue, NW., Washington, DC 20220.

Dates: Written comments should be received on or before November 30, 2009 to be assured of consideration.

Community Development Financial Institutions Fund

OMB Number: 1559–0016.

Type of Review: Revision.

Title: New Markets Tax Credit (NMTC) Program—Allocation Application.

Form: CDFI 0020.

Description: The New Markets Tax Credit (NMTC) Program will provide an incentive to investors in the form of a tax credit, which is expected to stimulate investment in private capital that, and in turn, will facilitate economic and community development in low-income communities. In order to qualify for an allocation of tax credits under the NMTC Program an entity

[15] 17 CFR 200.30–3(a)(12).

must be certified as a qualified community development entity and submit an allocation application to the CDFI Fund. Upon receipt of such applications, the CDFI Fund will conduct a competitive review process to evaluate applications for the receipt of NMTC allocations.

Respondents: Businesses and other for-profit institutions.

Estimated Total Burden Hours: 49,800 hours.

Clearance Officer: Ashanti McCallum (202) 622–9018, Community Development Financial Institutions Fund, Department of the Treasury, 601 13th Street, NW., Suite 200 South, Washington, DC 20005.

OMB Reviewer: Shagufta Ahmed (202) 395–7873, Office of Management and Budget, Room 10235, New Executive Office Building, Washington, DC 20503.

Celina Elphage,

Treasury PRA Clearance Officer.

[FR Doc. E9–26151 Filed 10–29–09; 8:45 am]

BILLING CODE 4810–70–P

DEPARTMENT OF THE TREASURY

Departmental Offices, Office of Small and Disadvantaged Business Utilization (OSDBU); Proposed Collection; Comment Request

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)). Currently, the Departmental Offices, OSDBU within the Department of the Treasury is soliciting comments concerning the Electronic Capability Statement (ECS).

DATES: Written comments should be received on or before December 31, 2009, to be assured of consideration.

ADDRESSES: Direct all written comments to the Department of the Treasury, Departmental Offices, OSDBU, ATTN: Robin Byrd, 1500 Pennsylvania Avenue, NW., Washington, DC 20220, MS: Metropolitan Square, Room 6091, (202) 622–8213; *http://www.treas.gov/osdbu.*

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the form(s) and instructions should be directed to the Department of the Treasury, Departmental Offices, OSDBU, ATTN: Robin Byrd, 1500 Pennsylvania Avenue, NW., Washington, DC 20220, MS: Metropolitan Square, Room 6091, (202) 622–8213; *http://www.treas.gov/osdbu.*

SUPPLEMENTARY INFORMATION:

Title: Electronic Capability Statement.

OMB Number: 1505–0220.

Abstract: The Electronic Capability Statement will be used by firms that wish to do business with the Department of the Treasury. The form will capture key information such as NAICS, contract and subcontract award information, and past performance. The information will be stored in a database. The database will be used by OSDBU, Treasury Acquisition staff and the Troubled Asset Relief Program to conduct research when searching for small businesses to perform on Treasury contracts.

Current Actions: The Electronic Capability Statement has been developed by the Chief Information Officer. The OSDBU is preparing to conduct a demonstration of the eCS and commence testing with the Department of the Treasury Bureaus and TARP. The OSDBU is also in the process of obtaining funds to purchase a dedicated server and equipment to implement the ECS.

Type of Review: Extension.

Affected Public: Business or other for-profit; Federal Government.

Estimated Number of Respondents: 420.

Estimated Total Annual Burden Hours: 54.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Dated: October 23, 2009.

Teresa Lewis,

Director, Office of Small and Disadvantaged Business Utilization.

[FR Doc. E9–26195 Filed 10–29–09; 8:45 am]

BILLING CODE 4810–25–P

Federal Register

Friday,

October 30, 2009

Part II

Environmental Protection Agency

40 CFR Parts 86, 87, 89 et al.

Mandatory Reporting of Greenhouse Gases; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 86, 87, 89, 90, 94, 98, 1033, 1039, 1042, 1045, 1048, 1051, 1054, 1065

[EPA–HQ–OAR–2008–0508; FRL–8963–5]

RIN 2060–A079

Mandatory Reporting of Greenhouse Gases

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is promulgating a regulation to require reporting of greenhouse gas emissions from all sectors of the economy. The final rule applies to fossil fuel suppliers and industrial gas suppliers, direct greenhouse gas emitters and manufacturers of heavy-duty and off-road vehicles and engines. The rule does not require control of greenhouse gases, rather it requires only that sources above certain threshold levels monitor and report emissions.

DATES: The final rule is effective on December 29, 2009. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of December 29, 2009.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2008–0508. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, e.g., confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through www.regulations.gov or in hard copy at EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue, NW., Washington, DC 20004. This Docket Facility 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.

FOR FURTHER INFORMATION CONTACT: Carole Cook, Climate Change Division, Office of Atmospheric Programs (MC–6207J), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460; *telephone number:* (202) 343–9263; *fax number:* (202) 343–2342; *e-mail address: GHGReportingRule@epa.gov.* For technical information and implementation materials, please go to the Web site *www.epa.gov/climatechange/emissions/ghgrulemaking.html.* You may also contact the Greenhouse Gas Reporting Rule Hotline at *telephone number:* (877) 444–1188; or *e-mail: ghgmrr@epa.gov.*

SUPPLEMENTARY INFORMATION:

Regulated Entities. The Administrator determined that this action is subject to the provisions of Clean Air Act (CAA) section 307(d). *See* CAA section 307(d)(1)(V) (the provisions of section 307(d) apply to ''such other actions as the Administrator may determine.''). The final rule affects fuel and chemicals suppliers, direct emitters of greenhouse gases (GHGs) and manufacturers of mobile sources and engines. Regulated categories and entities include those listed in Table 1 of this preamble:

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY

Category	NAICS	Examples of affected facilities
General Stationary Fuel Combustion Sources.	....	Facilities operating boilers, process heaters, incinerators, turbines, and internal combustion engines:
	211	Extractors of crude petroleum and natural gas.
	321	Manufacturers of lumber and wood products.
	322	Pulp and paper mills.
	325	Chemical manufacturers.
	324	Petroleum refineries, and manufacturers of coal products.
	316, 326, 339	Manufacturers of rubber and miscellaneous plastic products.
	331	Steel works, blast furnaces.
	332	Electroplating, plating, polishing, anodizing, and coloring.
	336	Manufacturers of motor vehicle parts and accessories.
	221	Electric, gas, and sanitary services.
	622	Health services.
	611	Educational services.
Electricity Generation	221112	Fossil-fuel fired electric generating units, including units owned by Federal and municipal governments and units located in Indian Country.
Adipic Acid Production	325199	Adipic acid manufacturing facilities.
Aluminum Production	331312	Primary Aluminum production facilities.
Ammonia Manufacturing	325311	Anhydrous and aqueous ammonia manufacturing facilities.
Cement Production	327310	Portland Cement manufacturing plants.
Ferroalloy Production	331112	Ferroalloys manufacturing facilities.
Glass Production	327211	Flat glass manufacturing facilities.
	327213	Glass container manufacturing facilities.
	327212	Other pressed and blown glass and glassware manufacturing facilities.
HCFC–22 Production and HFC–23 Destruction.	325120	Chlorodifluoromethane manufacturing facilities.
Hydrogen Production	325120	Hydrogen manufacturing facilities.
Iron and Steel Production	331111	Integrated iron and steel mills, steel companies, sinter plants, blast furnaces, basic oxygen process furnace shops.
Lead Production	331419	Primary lead smelting and refining facilities.
	331492	Secondary lead smelting and refining facilities.
Lime Production	327410	Calcium oxide, calcium hydroxide, dolomitic hydrates manufacturing facilities.
Nitric Acid Production	325311	Nitric acid manufacturing facilities.
Petrochemical Production	32511	Ethylene dichloride manufacturing facilities.
	325199	Acrylonitrile, ethylene oxide, methanol manufacturing facilities.
	325110	Ethylene manufacturing facilities.

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY—Continued

Category	NAICS	Examples of affected facilities
	325182	Carbon black manufacturing facilities.
Petroleum Refineries	324110	Petroleum refineries.
Phosphoric Acid Production	325312	Phosphoric acid manufacturing facilities.
Pulp and Paper Manufacturing	322110	Pulp mills.
	322121	Paper mills.
	322130	Paperboard mills.
Silicon Carbide Production	327910	Silicon carbide abrasives manufacturing facilities.
Soda Ash Manufacturing	325181	Alkalies and chlorine manufacturing facilities.
	212391	Soda ash, natural, mining and/or beneficiation.
Titanium Dioxide Production	325188	Titanium dioxide manufacturing facilities.
Zinc Production	331419	Primary zinc refining facilities.
	331492	Zinc dust reclaiming facilities, recovering from scrap and/or alloying purchased metals.
Municipal Solid Waste Landfills	562212	Solid waste landfills.
	221320	Sewage treatment facilities.
Manure Management	112111	Beef cattle feedlots.
	112120	Dairy cattle and milk production facilities.
	112210	Hog and pig farms.
	112310	Chicken egg production facilities.
	112330	Turkey Production.
	112320	Broilers and Other Meat type Chicken Production.
Suppliers of Coal Based Liquids Fuels	211111	Coal liquefaction at mine sites.
Suppliers of Petroleum Products	324110	Petroleum refineries.
Suppliers of Natural Gas and NGLs	221210	Natural gas distribution facilities.
	211112	Natural gas liquid extraction facilities.
Suppliers of Industrial GHGs	325120	Industrial gas manufacturing facilities.
Suppliers of Carbon Dioxide (CO_2)	325120	Industrial gas manufacturing facilities.
Mobile Sources	333618	Heavy-duty, non-road, aircraft, locomotive, and marine diesel engine manufacturing.
	336120	Heavy-duty vehicle manufacturing facilities.
	336312	Small non-road, and marine spark-ignition engine manufacturing facilities.
	336999	Personal watercraft manufacturing facilities.
	336991	Motorcycle manufacturing facilities.

Table 1 of this preamble is not intended to be exhaustive, but rather provides a guide for readers regarding facilities likely to be affected by this action. Table 1 of this preamble lists the types of facilities that EPA is now aware could be potentially affected by the reporting requirements. Other types of facilities and suppliers not listed in the table could also be subject to reporting requirements. To determine whether you are affected by this action, you should carefully examine the applicability criteria found in 40 CFR part 98, subpart A or the relevant criteria in the sections related to manufacturers of heavy-duty and off-road vehicles and engines. If you have questions regarding the applicability of this action to a particular facility, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Many facilities that are affected by the final rule have GHG emissions from multiple source categories listed in Table 1 of this preamble. Table 2 of this preamble has been developed as a guide to help potential reporters subject to the mandatory reporting rule identify the source categories (by subpart) that they may need to (1) consider in their facility applicability determination, and (2) include in their reporting. For each source category, activity, or facility type (e.g., electricity generation, aluminum production), Table 2 of this preamble identifies the subparts that are likely to be relevant. The table should only be seen as a guide. Additional subparts may be relevant for a given reporter. Similarly, not all listed subparts are relevant for all reporters.

TABLE 2—SOURCE CATEGORIES AND RELEVANT SUBPARTS

Source category (and main applicable subpart)	Other subparts recommended for review to determine applicability
General Stationary Fuel Combustion Sources.	
Electricity Generation	General Stationary Fuel Combustion, Suppliers of CO_2.
Adipic Acid Production	General Stationary Fuel Combustion.
Aluminum Production	General Stationary Fuel Combustion.
Ammonia Manufacturing	General Stationary Fuel Combustion, Hydrogen, Nitric Acid, Petroleum Refineries, Suppliers of CO_2.
Cement Production	General Stationary Fuel Combustion, Suppliers of CO_2.
Ferroalloy Production	General Stationary Fuel Combustion.
Glass Production	General Stationary Fuel Combustion.
HCFC–22 Production and HFC–23 Destruction	General Stationary Fuel Combustion.
Hydrogen Production	General Stationary Fuel Combustion, Petrochemicals, Petroleum Refineries, Suppliers of Industrial GHGs, Suppliers of CO_2.
Iron and Steel Production	General Stationary Fuel Combustion, Suppliers of CO_2.

TABLE 2—SOURCE CATEGORIES AND RELEVANT SUBPARTS—Continued

Source category (and main applicable subpart)	Other subparts recommended for review to determine applicability
Lead Production	General Stationary Fuel Combustion.
Lime Manufacturing	General Stationary Fuel Combustion.
Nitric Acid Production	General Stationary Fuel Combustion, Adipic Acid.
Petrochemical Production	General Stationary Fuel Combustion, Ammonia, Petroleum Refineries.
Petroleum Refineries	General Stationary Fuel Combustion, Hydrogen, Suppliers of Petroleum Products.
Phosphoric Acid Production	General Stationary Fuel Combustion.
Pulp and Paper Manufacturing	General Stationary Fuel Combustion.
Silicon Carbide Production	General Stationary Fuel Combustion.
Soda Ash Manufacturing	General Stationary Fuel Combustion.
Titanium Dioxide Production	General Stationary Fuel Combustion.
Zinc Production	General Stationary Fuel Combustion.
Municipal Solid Waste Landfills	General Stationary Fuel Combustion.
Manure Management	General Stationary Fuel Combustion.
Suppliers of Coal-based Liquid Fuels	Suppliers of Petroleum Products.
Suppliers of Petroleum Products	General Stationary Fuel Combustion.
Suppliers of Natural Gas and NGLs	General Stationary Fuel Combustion, Suppliers of CO_2.
Suppliers of Industrial GHGs	General Stationary Fuel Combustion, Hydrogen Production, Suppliers of CO_2.
Suppliers of Carbon Dioxide (CO_2)	General Stationary Fuel Combustion, Electricity Generation, Ammonia, Cement, Hydrogen, Iron and Steel, Suppliers of Industrial GHGs.
Mobile Sources	General Stationary Fuel Combustion.

Judicial Review. Under section 307(b)(1) of the CAA, judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by December 29, 2009. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. This section also provides a mechanism for us to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of this rule.'' Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20004, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20004. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document.

ARP Acid Rain Program
ASME American Society of Mechanical Engineers
ASTM American Society for Testing and Materials
BLS Bureau of Labor Statistics
CAA Clean Air Act
CAFE Corporate Average Fuel Economy
CAIR Clean Air Interstate Rule
CARB California Air Resources Board
CBI confidential business information
CCAR California Climate Action Registry
CCS carbon capture and sequestration
CEMS continuous emission monitoring system(s)
cf cubic feet
CFCs chlorofluorocarbons
CFR Code of Federal Regulations
CH_4 methane
CO_2 carbon dioxide
CO_2e CO_2-equivalent
COD chemical oxygen demand
DOE U.S. Department of Energy
DOT U.S. Department of Transportation
EAF electric arc furnace
ECOS Environmental Council of the States
EGUs electric generating units
EIA Energy Information Administration
EO Executive Order
EOR enhanced oil recovery
EPA U.S. Environmental Protection Agency
FY2008 fiscal year 2008
GHG greenhouse gas
GWP global warming potential
HCFC–22 chlorodifluoromethane (or $CHClF_2$)
HCFCs hydrochlorofluorocarbons
HFC–23 trifluoromethane (or CHF_3)
HFCs hydrofluorocarbons
HFEs hydrofluorinated ethers
HHV higher heating value
ICR information collection request
IPCC Intergovernmental Panel on Climate Change
kg kilograms
LDCs local natural gas distribution companies
LMP lime manufacturing plants
mmBtu/hr millions British thermal units per hour
MSW municipal solid waste
MW megawatts
MY mileage year
N_2O nitrous oxide
NACAA National Association of Clean Air Agencies
NAICS North American Industry Classification System
NEI National Emissions Inventory
NESHAP national emission standards for hazardous air pollutants
NF_3 nitrogen trifluoride
NGLs natural gas liquids
NSPS new source performance standards
NSR New Source Review
NTTAA National Technology Transfer and Advancement Act of 1995
O_3 ozone
ODS ozone-depleting substance(s)
OMB Office of Management and Budget
ORIS Office of Regulatory Information Systems
PFCs perfluorocarbons
PIN personal identification number
PSD Prevention of Significant Deterioration
QA quality assurance
QA/QC quality assurance/quality control
QAPP quality assurance performance plan
R&D research and development
RFA Regulatory Flexibility Act
RGGI Regional Greenhouse Gas Initiative
RICE reciprocating internal combustion engine
RIA regulatory impact analysis
SBREFA Small Business Regulatory Enforcement Fairness Act

scf standard cubic feet
SF_6 sulfur hexafluoride
SIP State Implementation Plan
SOP standard operating procedure
SSM startup, shutdown, and malfunction
TCR The Climate Registry
TRI Toxic Release Inventory
TSD technical support document
U.S. United States
UIC underground injection control
UMRA Unfunded Mandates Reform Act of 1995
UNFCCC United Nations Framework Convention on Climate Change
VMT vehicle miles traveled
VOC volatile organic compound(s)
WBCSD World Business Council for Sustainable Development
WCI Western Climate Initiative
WRI World Resources Institute
XML eXtensible Markup Language

Table of Contents

I. Background

A. Organization of This Preamble

This preamble is broken into several large sections, as detailed above in the Table of Contents. The paragraphs below describe the layout of the preamble and provide a brief summary of each section.

The first section of this preamble contains the basic background information about the origin of this rule, our legal authority, and how this proposal relates to other Federal, State, and regional efforts to address emissions of GHGs.

The second section of this preamble summarizes the general provisions of the final GHG reporting rule and identifies the major changes since proposal. It also provides a brief summary of public comments and responses on key design elements such as: (i) Source categories included, (ii) the level of reporting, (iii) applicability thresholds, (iv) selection of reporting and monitoring methods, (v) emissions verification, (vi) frequency of reporting and (vii) duration of reporting. It also addresses some of the legal comments on the statutory authority for the rule and the relationship of this rule to other CAA programs.

The third section of this preamble contains separate subsections addressing each individual source category of the proposed rule. Each source category section contains a summary of specific requirements of the rule for that source category, identifies major changes since proposal, and briefly discusses public comments and EPA responses specific to the source category. For example, comments on EPA's general approach for selecting monitoring methods are discussed in Section II of this preamble, whereas, comments on specific monitoring methods for individual source categories are discussed in Section III of this preamble.

The fourth section of this preamble summarizes rule requirements and addresses public comments pertaining to mobile sources.

The fifth section of this preamble explains how EPA plans to collect, manage and disseminate the data, while the sixth section describes the approach to compliance and enforcement. In both sections key public comments are summarized and responses are presented.

The seventh section provides the summary of the cost impacts, economic impacts, and benefits of the final rule and discusses comments on the regulatory impacts analyses. Finally, the last section discusses the various statutory and executive order requirements applicable to this rulemaking.

B. Background on the Final Rule

The fiscal year 2008 (FY2008) Consolidated Appropriations Act, signed on December 26, 2007, authorized funding for EPA to ''develop and publish a draft rule not later than nine months after the date of enactment of [the] Act, and a final rule not later than 18 months after the date of enactment of [the] Act, to require mandatory reporting of greenhouse gas emissions above appropriate thresholds in all sectors of the economy of the United States.'' Consolidated Appropriations Act, 2008, Public Law 110–161, 121 Stat. 1844, 2128 (2008).

The accompanying joint explanatory statement directed EPA to ''use its existing authority under the Clean Air Act'' to develop a mandatory GHG reporting rule. ''The Agency is further directed to include in its rule reporting of emissions resulting from upstream production and downstream sources, to the extent that the Administrator deems it appropriate.'' EPA interpreted that language to confirm that it was appropriate for the Agency to exercise its CAA authority to develop this rulemaking. The joint explanatory statement further states that ''[t]he Administrator shall determine appropriate thresholds of emissions above which reporting is required, and how frequently reports shall be submitted to EPA. The Administrator shall have discretion to use existing reporting requirements for electric generating units (EGUs)'' under section 821 of the 1990 CAA Amendments.

On April 10, 2009 (74 FR 16448), EPA proposed the GHG reporting rule. EPA held two public hearings, and received approximately 16,800 written public comments. The public comment period ended on June 9, 2009.

In addition to the public hearings, EPA had an open door policy, similar to the outreach conducted during the development of the proposal. As a result, EPA has met with over 4,000 people and 135 groups since proposal signature (March 10, 2009). Details of these meetings are available in the docket (EPA–HQ–OAR–2008–0508).

EPA developed this final rule and included reporting of GHGs from the facilities that we determined appropriately responded to the direction in the FY2008 Consolidated Appropriations Act [1] (e.g., capturing approximately 85 percent of U.S. GHG emissions through reporting by direct emitters as well as suppliers of fossil fuels and industrial gases and manufacturers of heavy-duty and off-road vehicles and engines). There are, however, many additional types of data and reporting that the Agency deems important and necessary to address an issue as large and complex as climate change (e.g., indirect emissions, electricity use). In that sense, one could view this final rule as narrowly focused on certain sources of emissions and upstream suppliers. As described in Sections I.C and D of this preamble as well as in the comment response sections, there are several existing programs at the Federal, regional and State levels that also collect valuable information to inform and implement policies necessary to address climate change. Many of these programs are focused on cost-effectively reducing GHG emissions through improvements in energy efficiency and by other means. These programs are an essential component of the Nation's climate policy, and the targeted nature of this rule should not be interpreted to mean that the data EPA collects through this program are the only data necessary to support the full range of climate policies and programs.

Today's rule requires the reporting of the GHG emissions that could result from the combustion or use of fossil fuel or industrial gas that is produced or imported from upstream sources such as fuel suppliers, as well as reporting of GHG emissions directly emitted from facilities (downstream sources) through their processes and/or from fuel combustion, as appropriate. Vehicle and engine manufacturers are also required to report emissions rate data on the heavy-duty and off-road engines they produce. The rule also establishes appropriate thresholds and frequency for reporting.

The rule requires reporting of annual emissions of carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and other fluorinated gases (e.g., nitrogen trifluoride (NF_3) and hydrofluorinated ethers (HFEs)). It also includes provisions to ensure the accuracy of emissions data through monitoring, recordkeeping and verification requirements. The rule applies to certain downstream facilities that emit GHGs (primarily large facilities emitting 25,000 metric tons or more of CO_2 equivalent (CO_2e) GHG emissions per year) and to most upstream suppliers of fossil fuels and industrial GHGs, as well as to manufacturers of vehicles and engines. Reporting is at the facility level, except certain suppliers and vehicle and engine manufacturers report at the corporate level.

C. Legal Authority

As proposed, EPA is promulgating this rule under its existing CAA authority, specifically authorities provided in CAA sections 114 and 208. As discussed further below and in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues'', we are not citing the FY 2008 Consolidated Appropriations Act as the statutory basis for this action. While that law required that EPA spend no less than $3.5 million on a rule requiring the mandatory reporting of GHG emissions, it is the CAA, not the Appropriations Act, that EPA is citing as the authority to gather the information required by this rule.

Sections 114 and 208 of the CAA provide EPA broad authority to require the information mandated by this rule because such data will inform and are relevant to EPA's carrying out a wide variety of CAA provisions. As discussed in the proposed rule, CAA section 114(a)(1) authorizes the Administrator to require emissions sources, persons subject to the CAA, or persons whom the Administrator believes may have necessary information to monitor and report emissions and provide such other information the Administrator requests for the purposes of carrying out any provision of the CAA (except for a provision of title II with respect to manufacturers of new motor vehicles or

[1] Consolidated Appropriations Act, 2008, Public Law 110–161, 121 Stat. 1844, 2128. Congress reaffirmed interest in a GHG reporting rule, and provided additional funding, in the 2009 Appropriations Act (Consolidated Appropriations Act, 2009, Public Law 110–329, 122 Stat. 3574–3716).

new motor vehicle engines).[2] Section 208 of the CAA provides EPA with similar broad authority regarding the manufacturers of new motor vehicles or new motor vehicle engines, and other persons subject to the requirements of parts A and C of title II. We note that while climate change legislation approved by the U.S. House of Representatives would provide EPA additional authority for a GHG registry similar to today's rule, and would do so for purposes of that pending legislation, this final rule is authorized by, and the information being gathered by the rule is relevant to implementing, the existing CAA. We expect, however, that the information collected by this final rule will also prove useful to legislative efforts to address GHG emissions.

As discussed in the proposal, emissions from direct emitters should inform decisions about whether and how to use CAA section 111 to establish new source performance standards (NSPS) for various source categories emitting GHGs, including whether there are any additional categories of sources that should be listed under CAA section 111(b). Similarly, the information required of manufacturers of mobile sources should support decisions regarding treatment of those sources under CAA sections 202, 213 or 231. In addition, the information from fuel suppliers would be relevant in analyzing whether to proceed, and particular options for how to proceed, under CAA section 211(c) regarding fuels, or to inform action concerning downstream sources under a variety of Title I or Title II provisions. The data overall also would inform EPA's implementation of CAA section 103(g) regarding improvements in non-regulatory strategies and technologies for preventing or reducing air pollutants (e.g., EPA's voluntary GHG reduction programs such as the non-CO_2 partnership programs and ENERGY STAR, described below in Section I.D of this preamble and Section II of the proposal preamble (74 FR 16448, April 10, 2009)).

D. How does this rule relate to EPA and U.S. government climate change efforts?

This reporting rule is one specific action EPA has taken, consistent with the Congressional request contained in the FY2008 Consolidated Appropriations Act, to collect GHG emissions data. EPA has recently announced a number of climate change related actions, including proposed findings that GHG emissions from new motor vehicles and engines contribute to air pollution which may reasonably be anticipated to endanger public health and welfare (74 FR 18886, April 24, 2009, ''Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act''), and an intent to regulate light duty vehicles, jointly published with U.S. Department of Transportation (DOT) (74 FR 24007, May 22, 2009, ''Notice of Upcoming Joint Rulemaking To Establish Vehicle GHG Emissions and CAFE Standards''). The Administrator has also announced her reconsideration of the memo entitled ''EPA's Interpretation of Regulations that Determine Pollutants Covered By Federal Prevention of Significant Deterioration (PSD) Permit Program'' (73 FR 80300, December 31, 2008), and granted California's request for a waiver for its GHG vehicle standard (74 FR 32744, July 8, 2009). These are all separate actions, some of which are related to EPA's response to the U.S. Supreme Court's decision in *Massachusetts* v. *EPA*. 127 S. Ct. 1438 (2007). This rulemaking does not indicate EPA has made any final decisions on pending actions. In fact the mandatory GHG reporting program will provide EPA, other government agencies, and outside stakeholders with economy-wide data on facility-level (and in some cases corporate-level) GHG emissions, which should assist in future policy development.

Accurate and timely information on GHG emissions is essential for informing many future climate change policy decisions. Although additional data collection (e.g., for other source categories or to support additional policy or program needs) will no doubt be required as the development of climate policies evolves, the data collected in this rule will provide useful information for a variety of polices. Through data collected under this rule, EPA, States and the public will gain a better understanding of the relative emissions of specific industries across the nation and the distribution of emissions from individual facilities within those industries. The facility-specific data will also improve our understanding of the factors that influence GHG emission rates and actions that facilities could in the future or already take to reduce emissions, including under traditional and more flexible programs.

As discussed in more detail in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues'' and elsewhere, EPA is promulgating this rule to gather GHG information to assist EPA in assessing how to address GHG emissions and climate change under the Clean Air Act. However, we expect that the information will prove useful for other purposes as well. For example, using the rich data set provided by this rulemaking, EPA, States and the public will be able to track emission trends from industries and facilities within industries over time, particularly in response to policies and potential regulations. The data collected by this rule will also improve the U.S. government's ability to formulate climate policies, and to assess which industries might be affected, and how these industries might be affected by potential policies. Finally, EPA's experience with other reporting programs is that such programs raise awareness of emissions among reporters and other stakeholders, and thus contribute to efforts to identify and implement emission reduction opportunities. These data can also be coupled with efforts at the local, State and Federal levels to assist corporations and facilities in determining their GHG footprints and identifying opportunities to reduce emissions (e.g., through energy audits or other forms of assistance).

This GHG reporting program supplements and complements, rather than duplicates, existing U.S. government programs (e.g., climate policy and research programs). For example, EPA anticipates that facility-level GHG emissions data will lead to improvements in the quality of the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (Inventory), which EPA prepares annually, with input from several other agencies, and submits to the Secretariat of the United Nations Framework Convention on Climate Change (UNFCCC).

A number of EPA voluntary partnership programs include a GHG emissions and/or reductions reporting component (e.g., Climate Leaders, the Natural Gas STAR program, Energy Star). This mandatory reporting program has broader coverage of U.S. GHG emissions than most voluntary programs, which typically focus on a specific industry and/or goal (e.g., reduction of CH_4 emissions or development of corporate inventories). It will improve EPA's understanding of emissions from facilities not currently included in these programs and increase the coverage of these industries. That said, we expect ongoing and potential new voluntary programs to continue to

[2] Although there are exclusions in CAA section 114(a)(1) regarding certain title II requirements applicable to manufacturers of new motor vehicle and motor vehicle engines, CAA section 208 authorizes the gathering of information related to those areas.

play an important role in achieving low-cost reductions in GHG emissions.

In addition to EPA's programs mentioned above, U.S. Department of Energy (DOE) EIA implements a voluntary GHG registry under section 1605(b) of the Energy Policy Act, which is further discussed in Section II of the proposal preamble (74 FR 16458, April 10, 2009). Under EIA's ''1605(b) program,'' reporters can choose to prepare an entity-wide GHG inventory and identify specific GHG reductions made by the entity.[3] EPA's mandatory GHG reporting rule covers a much broader set of reporters, primarily at the facility rather than entity-level, but this reporting rule is not designed with the specific intent of reporting of emission reductions, as is the 1605(b) program.

For additional information about these programs, *please see* Sections I and II of the preamble to the proposed GHG reporting rule (74 FR 16454, April 10, 2009).

E. How does this rule relate to other State and Regional Programs?

There are several existing State and regional GHG reporting and/or reduction programs summarized in Section II of the proposal preamble (74 FR 16457, April 10, 2009). These are important programs that not only led the way in reporting of GHG emissions before the Federal government acted but also assist in quantifying the GHG reductions achieved by various policies. Many of these programs collect different or additional data as compared to this rule. For example, State programs may establish lower thresholds for reporting or request information on areas not addressed in EPA's reporting rule (e.g., electricity use or emission related to other indirect sources). States collecting additional information have determined that these data are necessary to implement their specific climate policies and programs. EPA agrees that State and regional programs are crucial to achieving emissions reductions, and this rule does not preempt any other programs.

EPA's GHG reporting rule is a specific single action that was developed in response to the Appropriations Act, and therefore is targeted to accomplish the purpose of the language of the Appropriations Act and serve EPA's purposes under the CAA. As State experience has demonstrated, we recognize that in order to address the breadth of climate change issues there will likely be a need to collect additional data from sources subject to this rule as well as other sources. The timing and nature of these additional needs will be dependent on the types of programs and actions the Agency has underway or may develop and implement in response to future policy developments and/or new requests from Congress. Addressing climate change will require a suite of policies and programs and this reporting rule is just one effort to collect information to inform those policies.

EPA is committed to working with State and regional programs to coordinate implementation of reporting programs, reduce burden on reporters, provide timely access to verified emissions data, establish mechanisms to efficiently share data, and harmonize data systems to the extent possible. See Section II.O of this preamble for a summary of public comments and responses on the role of States and the relationship of this GHG reporting rule to other programs. See Section VI.B of this preamble for a summary of comments and responses on State delegation of rule implementation and enforcement. As mentioned above, for additional information about existing State and regional programs *please see* Section II of the proposal preamble (74 FR 16457, April 10, 2009) and the docket EPA–HQ–OAR–2008–0508.

II. General Requirements of the Rule

The rule requires reporting of annual emissions of CO_2, CH_4, N_2O, SF_6, HFCs, PFCs, and other fluorinated gases (as defined in 40 CFR part 98, subpart A) in metric tons. The final 40 CFR part 98 applies to certain downstream facilities that emit GHGs, and to certain upstream suppliers of fossil fuels and industrial GHGs. For suppliers, the GHG emissions reported are the emissions that would result from combustion or use of the products supplied. The rule also includes provisions to ensure the accuracy of emissions data through monitoring, recordkeeping and verification requirements. Reporting is at the facility[4] level, except that certain suppliers of fossil fuels and industrial gases would report at the corporate level.

In addition, GHG reporting by manufacturers of heavy-duty and off-road vehicles and engines is required, by incorporating new requirements into the existing reporting requirements for motor vehicles and engine manufacturers in 40 CFR parts 86, 87, 89, 90, 94, 1033, 1039, 1042, 1045, 1048, 1051, 1054, and 1065. A summary of the reporting requirements for manufacturers of motor vehicles and engines is contained in Section IV of this preamble. A discussion of public comments and responses that pertain to motor vehicles is also contained in Section IV of this preamble and in the ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Motor Vehicle and Engine Manufacturers.''

The remainder of this section summarizes the general provisions of 40 CFR part 98, identifies changes since the proposed rule, and summarizes key public comments and responses on the general requirements of the rule.

A. Summary of the General Requirements of the Final Rule

1. Applicability

Reporters must submit annual GHG reports for the following facilities and supply operations.

• Any facility that contains any source category (as defined in 40 CFR part 98, subparts C through JJ) that is listed below in any calendar year starting in 2010.[5] For these facilities, the annual GHG report covers all source categories and GHGs for which calculation methodologies are provided in 40 CFR part 98, subparts C through JJ.

—Electricity generating facilities that are subject to the Acid Rain Program (ARP) or otherwise report CO_2 mass emissions year-round through 40 CFR part 75.
—Adipic acid production.
—Aluminum production.
—Ammonia manufacturing.
—Cement production.
—HCFC–22 production.
—HFC–23 destruction processes that are not co-located with a HCFC–22 production facility and that destroy more than 2.14 metric tons of HFC–23 per year.
—Lime manufacturing.
—Nitric acid production.
—Petrochemical production.
—Petroleum refineries.

[3] Under the 1605(b) program an ''entity'' is defined as ''the whole or part of any business, institution, organization or household that is recognized as an entity under any U.S. Federal, State or local law that applies to it; is located, at least in part, in the U.S.; and whose operations affect U.S. greenhouse gas emissions.'' (*http://www.pi.energy.gov/enhancingGHGregistry/*)

[4] For the purposes of this rule, facility means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

[5] Unless otherwise noted, years and dates in this notice refer to calendar years and dates.

—Phosphoric acid production.
—Silicon carbide production.
—Soda ash production.
—Titanium dioxide production.
—Municipal solid waste (MSW) landfills that generate CH_4 in amounts equivalent to 25,000 metric tons CO_2e or more per year, as determined according to 40 CFR part 98, subpart HH.
—Manure management systems that emit CH_4 and N_20 (combined) in amounts equivalent to 25,000 metric tons CO_2e or more per year, as determined according to 40 CFR part 98, subpart JJ.

• Any facility that contains any source category (as defined in 40 CFR part 98, subparts C through JJ) that is listed below and that emits 25,000 metric tons CO_2e or more per year in combined emissions from stationary fuel combustion units, miscellaneous use of carbonates and all of the source categories listed in this paragraph in any calendar year starting in 2010. For these facilities, the annual GHG report must cover all source categories and GHGs for which calculation methodologies are provided in 40 CFR part 98, subparts C through JJ.
—Ferroalloy Production.
—Glass Production.
—Hydrogen Production.
—Iron and Steel Production.
—Lead Production.
—Pulp and Paper Manufacturing.
—Zinc Production.

• Any facility that in any calendar year starting in 2010 meets all three of the conditions listed in this paragraph. For these facilities, the annual GHG report covers emissions from stationary fuel combustion sources only. For 2010 only, the facilities can submit an abbreviated GHG report according to 40 CFR 98.3(d).
—The facility does not meet the requirements described in the above two paragraphs;
—The aggregate maximum rated heat input capacity of the stationary fuel combustion units at the facility is 30 million British thermal units per hour (mmBtu/hr) or greater; and
—The facility emits 25,000 metric tons CO_2e or more per year from all stationary fuel combustion sources.[6]

• Any supplier (as defined in 40 CFR part 98, subparts LL through PP) of any of the products as listed below in any calendar year starting in 2010. For these suppliers, the annual GHG report covers all applicable products for which calculation methodologies are provided in 40 CFR part 98, subparts KK through PP.
—*Coal-based liquid fuels:* All producers of coal-to-liquid fuels; importers and exporters of coal-to-liquid fuels with annual imports or annual exports that are equivalent to 25,000 metric tons CO_2e or more per year.
—*Petroleum products:* All petroleum refiners that distill crude oil; importers and exporters of petroleum products with annual imports or annual exports that are equivalent to 25,000 metric tons CO_2e or more per year.
—*Natural gas and natural gas liquids (NGLs):* All natural gas fractionators and all local natural gas distribution companies (LDCs).
—*Industrial GHGs:* All producers of industrial GHGs; importers and exporters of industrial GHGs with annual bulk imports or exports of N_2O, fluorinated GHGs, and CO_2 that in combination are equivalent to 25,000 metric tons CO_2e or more per year.
—*CO_2:* All producers of CO_2; importers and exporters of CO_2 with annual bulk imports or exports of N_2O, fluorinated GHGs, and CO_2 that in combination are equivalent to 25,000 metric tons CO_2e or more per year.

• Research and development activities (as defined in 40 CFR 98.6) are not considered to be part of any source category subject to the rule.

It is important to note that the applicability criteria apply to a facility's annual emissions or a supplier's annual quantity of product supplied.[7] For example, while a facility's emissions may be below 25,000 metric tons CO_2e in January, if the cumulative emissions for the calendar year are 25,000 metric tons CO_2e or more at the end of December, the rule applies and the reporter must submit an annual GHG report for that facility. Therefore, it is in a facility's or supplier's interest to collect the GHG data required by the rule if they think they will meet or exceed the applicability criteria in 40 CFR 98.2 by the end of the year. EPA plans to have tools and guidance available to assist potential reporters in assessing whether the rule applies to their facilities or supply operations.

2. Schedule for Reporting

Reporters must begin collecting data on January 1, 2010. The first annual GHG report is due on March 31, 2011, for GHGs emitted or products supplied during 2010. For a portion of 2010, the rule allows reporters to use best available monitoring methods for parameters that cannot reasonably be measured according to the monitoring and quality assurance/quality control (QA/QC) requirements of the relevant subpart as described in Sections II.A.3 and II.G of this preamble.

Reports are submitted annually. For EGUs that are subject to the ARP, reporters must continue to report CO_2 mass emissions quarterly, as required by the ARP, in addition to providing annual GHG reports under this rule. Reporters must submit GHG data on an ongoing, annual basis. The snapshot of information provided by a one-time information collection request (ICR) would not provide the type of ongoing information which could inform the variety of potential CAA policy options being evaluated for addressing climate change.

Once subject to this reporting rule, reporters must continue to submit GHG reports annually. A reporter can cease reporting if the required annual GHG reports demonstrate that reported GHG emissions are either (1) less than 25,000 metric tons of CO_2e per year for five consecutive years or (2) less than 15,000 metric tons of CO_2e per year for three consecutive years. The reporter must notify EPA that they intend to cease reporting and explain the reasons for the reduction in emissions. This provision applies to all facilities and suppliers subject to the rule, regardless of their applicability category (i.e., whether rule applicability was initially triggered by an ''all-in'' source category or a source category with a 25,000 metric tons CO_2e threshold). The reporter must keep records for all five consecutive years in which emissions were less than 25,000 metric tons per year, or all three consecutive years in which emissions were less than 15,000 metric tons per year, as appropriate. If GHG emissions (or quantities in products supplied) subsequently increase to 25,000 metric tons CO_2e in any calendar year, the reporter must again begin annual reporting. The rule also contains a provision to allow facilities and suppliers to notify EPA and stop reporting if they close all GHG-emitting processes and operations covered by the rule.

If reporters discover or are notified by EPA of errors in an annual GHG report, they must submit a revised GHG report within 45 days.

3. What has to be included in the annual GHG report?

Reporters must include the following information in each annual GHG report:

[6] This does not include portable equipment, emergency generators, or emergency equipment as defined in the rule.

[7] Supplied means produced, imported, or exported.

• Facility name or supplier name (as appropriate) and physical street address including the city, State, and zip code.

• Year and months covered by the report, and date of report submittal.

• For facilities that directly emit GHG:

—Annual facility emissions (excluding biogenic CO_2), expressed in metric tons of CO_2e per year, aggregated for all GHG from all source categories in 40 CFR part 98, subparts C through JJ that are located at the facility.

—Annual emissions of biogenic CO_2 (i.e., CO_2 from combustion of biomass) aggregated for all applicable source categories in subparts C through JJ located at the facility.

—Annual GHG emissions for each of the source categories located at the facility, by gas. Gases are: CO_2 (excluding biogenic CO_2), biogenic CO_2, CH_4, N_2O, and each fluorinated GHG.

—Within each source category, emissions broken out at the level specified in the respective subpart (e.g., some source categories require reporting for each individual unit or each process line).

—Additional data specified in the applicable subparts for each source category. This includes activity data (e.g., fuel use, feedstock inputs) that were used to generate the emissions data and additional data to support QA/QC and emissions verification.

—Total pounds of synthetic fertilizer produced through nitric acid or ammonia production and total nitrogen contained in that fertilizer.

• For suppliers: [8]

—Annual quantities of each GHG that would be emitted from combustion or use [9] of the products supplied, imported, or exported during the year. Report this for each applicable supply category in 40 CFR part 98 subparts KK through PP, by gas. Also report the total quantity, expressed in metric tons of CO_2e, aggregated for all GHGs from all applicable supply categories.

—Additional data specified in the applicable subparts for each supply category. This includes data used to calculate GHG quantities or needed to support QA/QC and verification.

• A written explanation if the reporter changes GHG calculation methodologies during the reporting period.

• If best available monitoring methods were used for part of calendar year 2010, a brief description of the methods used.

• Each data element for which a missing data procedure was used according to the procedures of an applicable subpart and the total number of hours in the year that a missing data procedure was used for each data element.

• A signed and dated certification statement provided by the Designated Representative of the owner or operator.

Note that in some cases, the same facility is subject to the rule requirements for direct emitters as well as for suppliers. For example, petroleum refineries are suppliers of petroleum products (40 CFR part 98, subpart NN) and also directly emit GHGs from petroleum refining (40 CFR part 98, subpart Y), general stationary fuel combustion (40 CFR part 98, subpart C), and possibly other source categories located at a refinery. In such cases, reporters must report the information in both the facility and supplier bullets listed above.

EPA will protect any information claimed as CBI in accordance with regulations in 40 CFR part 2, subpart B. However, note that in general, emission data collected under CAA sections 114 and 208 shall be available to the public and cannot be withheld as CBI.[10]

Special Provisions for Reporting Year 2010. During January 1, 2010 through March 31, 2010, reporters may use best available monitoring methods for any parameter (e.g., fuel use, daily carbon content of feedstock by process line) that cannot reasonably be measured according to the monitoring and QA/QC requirements of a relevant subpart. The reporter must still use the calculation methodologies and equations in the ''Calculating GHG Emissions'' sections of each relevant subpart, but may use the best available monitoring method for any parameter for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2010. Starting no later than April 1, 2010, the reporter must begin following all applicable monitoring and QA/QC requirements of this part, unless they submit a request to EPA showing that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by April 1, 2010, and EPA approves the request. EPA will not approve use of best available methods beyond December 31, 2010. Best available monitoring methods include any of the following methods:

• Monitoring methods currently used by the facility that do not meet the specifications of a relevant subpart.

• Supplier data.

• Engineering calculations.

• Other company data.

Abbreviated GHG Report for Facilities Containing Only General Stationary Fuel Combustion Sources. In lieu of a full annual GHG report, reporters may submit an abbreviated GHG report for 2010 emissions from existing facilities that were in operation as of January 1, 2010, and are required to report only their stationary combustion source emissions per 40 CFR 98.2(a)(3). The abbreviated report contains total facility GHG emissions aggregated for all stationary combustion units calculated according to any of the methods in 40 CFR 98.33(a) and expressed in metric tons of CO_2, CH_4, N_2O, and CO_2e. While the breakdown of emissions by individual combustion units and the activity data used to calculate the emissions do not need to be reported as part of the abbreviated GHG report, the calculation variables used in the selected method must be reported. For calendar year 2011, all reporters must submit the full annual GHG report containing all required information.

4. How is the report submitted?

The reports must be submitted electronically, in a format to be specified by the Administrator after publication of the final rule.[11] To the extent practicable, we plan to adapt existing EPA facility reporting programs to accept GHG emissions data. We are developing a new electronic data reporting system for source categories or suppliers for which it is not feasible to use existing EPA reporting mechanisms.

Each report must contain a signed certification by a Designated Representative of the facility. On behalf of the owners and operators, the Designated Representative must certify under penalty of law that the report has been prepared in accordance with the requirements of 40 CFR part 98 and that the information contained in the report is true and accurate.

5. What records must be retained?

Each reporter must also retain and make available to EPA upon request the

[8] Suppliers include producers, importers, and exporters of fuels and industrial gases. The level of reporting for suppliers is specified in the rule. Most report at the facility level. Imports and exports are reported at the corporate level.

[9] ''Use'' for purposes of industrial GHGs presumes that there will be 100 percent release of the GHG.

[10] Although CBI determinations are usually made on a case-by-case basis, EPA has discussed in an earlier **Federal Register** notice what constitutes emissions data that cannot be withheld as CBI (956 FR 7042–7043, February 21, 1991). In addition, as discussed in Section II.R of this preamble, EPA will be initiating a separate notice and comment process to make CBI and emissions data determinations for the categories of data collected under this rulemaking.

[11] For more information about the reporting format please see Section V of this preamble.

following records for three years in an electronic or hard-copy format as appropriate:

- A list of all units, operations, processes and activities for which GHG emissions are calculated.
- The data used to calculate the GHG emissions for each unit, operation, process, and activity, categorized by fuel or material type. These data include, but are not limited to:

—The GHG emissions calculations and methods used.
—Analytical results for the development of site-specific emissions factors.
—The results of all required analyses for high heat value, carbon content, or other required fuel or feedstock parameters.
—Any facility operating data or process information used for the GHG emissions calculations.

- The annual GHG reports.
- Missing data computations. For each missing data event, also retain a record of the duration of the event, actions taken to restore malfunctioning monitoring equipment, the cause of the event, and the actions taken to prevent or minimize occurrence in the future.
- A written GHG monitoring plan containing the information specified in 40 CFR 98.3(g)(5).
- The results of all required certification and quality assurance (QA) tests of CEMS, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.
- Maintenance records for all CEMS, flow meters, and other instrumentation used to provide data for the GHGs reported.
- Any other data specified in any applicable subpart of 40 CFR part 98. Examples of such data could include the results of sampling and analysis procedures required by the subparts (e.g., fuel heat content, carbon content of raw materials, and flow rate) and other data used to calculate emissions.

B. Summary of the Major Changes Since Proposal

EPA received approximately 16,800 public comments on the proposed rulemaking. As mentioned earlier in this preamble, we had two public hearings and conducted an unprecedented level of outreach between signature of the proposal and the close of the public comment period. Below are the major changes to the program since the proposal. The rationale for these and any other significant changes can be found in this preamble or in the ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments.''

- Reduced the number of source categories included in the final rule as we further consider comments and options on several categories.[12]
- Added a mechanism in 40 CFR 98.2 to allow facilities and suppliers that report less than 25,000 metric tons of CO_2e for five consecutive years, or less than 15,000 metric tons for 3 consecutive years, to cease annual reporting to EPA.
- Added a mechanism in 40 CFR 98.2 to allow facilities and suppliers that stop operating all GHG-emitting processes and operations covered by the rule to cease annual reporting to EPA.
- Added a provision in 40 CFR 98.3 for submittal of revised annual GHG reports to correct errors.
- Added provisions in 40 CFR 98.3 to allow use of best available monitoring methods for part of calendar year 2010.
- Added, in 40 CFR 98.3, calibration requirements for monitoring instruments including an accuracy specification of plus or minus five percent for flow meters.
- Excluded R&D activities from reporting under 40 CFR part 98 by adding an exclusion in 40 CFR 98.2.
- Revised the requirements of the Designated Representative in 40 CFR 98.4 to align them with those in 40 CFR part 75 (ARP regulations).
- Changed record retention to three years instead of five years for most records (40 CFR 98.3).
- In the recordkeeping section (40 CFR 98.3), clarified the contents of the monitoring plan (called the quality assurance performance plan (QAPP) at proposal).
- Edited references to the stationary fuel combustion subpart to improve consistency and edited the CEMS language in several subparts for consistency and to clarify when CEMS are used and under what circumstances upgrades are needed.
- Revised several definitions in 40 CFR part 98, subpart A to address comments.
- In several subparts of 40 CFR part 98, moved some of the data elements listed in the recordkeeping section of the proposed rule to the reporting section. In general, these changes were made to provide sufficient data for EPA to verify the reported emissions using the verification approach described in Section II.N of this preamble. Specific changes and reasons for them are summarized in the relevant source category sections within Section III of this preamble.

[12] See the following sections of this preamble for discussion of source categories not included in today's final rule: sections III.I (electronics manufacturing), III.J (ethanol production), III.L (fluorinated GHG production), III.M (food processing), III.T (magnesium production), III.W (oil and natural gas systems), III.DD (SF_6 from electrical equipment), III.FF (underground coal mines), III.HH (industrial landfills are not included in today's rule, but MSW landfills are covered by the rule), III.II (wastewater treatment), and III.KK (suppliers of coal).

C. Summary of Comments and Responses on GHGs To Report

This section contains a brief summary of major comments and responses on the issue of which GHGs to report. A large number of comments were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Selection of Reporting Thresholds, Greenhouse Gases, and De Minimis Provisions.'' Reponses to comments on fluorinated gases can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Suppliers of Industrial GHGs.''

Comment: Many commenters supported reporting of the GHGs included in the proposed rule: CO_2, CH_4, N_2O, HFCs, PFCs, SF_6, and other fluorinated compounds. Many commenters noted that IPCC and national inventories focus on these gases, and that they are directly emitted by human activities, long-lived in the atmosphere, and contribute to global climate change. A few of these also stated that collection of data on these gases is useful for future GHG policy development. While some commenters suggested collecting data on fewer gases or requiring reporting of additional gases, most agreed with the proposed list.

Some commenters raised concerns that the proposed definition of fluorinated GHGs was broad and included compounds for which global warming potentials (GWPs) were not currently available.

Response: The final rule requires reporting of the same gases as the proposed rule. These are the most abundantly emitted GHGs that result from human activity. They are not currently controlled by mandatory Federal programs and, with the exception of the CO_2 emissions data reported by EGUs subject to the ARP, data on their emissions are also not reported under mandatory Federal programs. CO_2 is the most abundant GHG directly emitted by human activities, and is a significant driver of climate change. The global anthropogenic combined heating effect of CH_4, N_2O, HFCs, PFCs, SF_6, and the other fluorinated compounds are also significant: About 40 percent as large as the CO_2 heating effect according to the Fourth Assessment Report of the IPCC.

The IPCC focuses on CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6 for both scientific assessments and emissions inventory purposes because these are long-lived, well-mixed GHGs not controlled by the Montreal Protocol as Substances that Deplete the Ozone (O_3) Layer. These GHGs are directly emitted by human activities, are reported annually in EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks*, and are a major focus of the climate change research and policy communities. The IPCC also included methods for accounting for emissions from several specified fluorinated gases in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.[13] These gases include fluorinated ethers, which are used in electronics, in anesthetics, and as heat transfer fluids. These fluorinated compounds are long-lived in the atmosphere and have high GWPs, like the HFCs, PFCs, and SF_6. In many cases these fluorinated gases are used in growing industries (e.g., electronics) or as substitutes for HFCs. As such, EPA is requiring reporting of these gases to ensure that the Agency has an accurate understanding of the emissions and uses of these gases, particularly as those uses expand.

There are other GHGs and aerosols that have climatic warming effects that we are not including in this rule: water vapor, chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs), halons, tropospheric O_3, and black carbon. The reasons why we are not requiring reporting of these gases and aerosols under this rule are contained in Section IV.A of the preamble to the proposed rule (74 FR 16464, April 10, 2009) and in the ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Selection of Reporting Thresholds, Greenhouse Gases, and De Minimis Provisions.''

In response to comments, the definition of fluorinated gases to report has been changed. See Section III.OO of this preamble (Suppliers of Industrial GHGs) for the response to comments on fluorinated gases to be reported.

[13] 2006 IPCC Guidelines for National Greenhouse Gas Inventories. The National Greenhouse Gas Inventories Programme, H.S. Eggleston, L. Buendia, K. Miwa, T. Ngara, and K. Tanabe (eds), hereafter referred to as the ''2006 IPCC Guidelines'' are found at: *http://www.ipcc.ch/ipccreports/methodology-reports.htm*. For additional information on these gases please see Table A–1 in proposed 40 CFR part 98, subpart A and the Suppliers of Industrial GHGs TSD (EPA–HQ–OAR–2008–0508–041).

D. Summary of Comments and Responses on Source Categories To Report

This section contains a brief summary of major comments and responses on which source categories must report. A large number of comments were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Selection of Source Categories to Report and Level of Reporting.''

1. Reduction in Number of Source Categories Included in the Final Rule

Comment: While many commenters agreed with the source categories selected for inclusion in the proposed rule, some commenters objected to the inclusion of specific source categories. Some also expressed concern that there might not be sufficient time for EPA to consider and address public comments and finalize the rules by fall 2009 for particular source categories.

Response: In today's notice EPA is promulgating subparts that require reporting for most of the source categories included in the proposed rule. For these categories, EPA fully considered and addressed the public comments, and has determined that the source categories should be included in the rule for reasons stated in Section IV.B of the preamble for the proposed rule (74 FR 16465, April 10, 2009), the ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments: EPA's Response to Public Comments, Selection of Source Categories to Report and Level of Reporting'', and the relevant comment response volumes for each of the individual source categories. However, at this time EPA is not going final with the following subparts as we further evaluate public comments:

- Electronics manufacturing
- Ethanol production
- Fluorinated GHG production
- Food processing
- Magnesium production
- Oil and natural gas systems
- SF_6 from electrical equipment
- Underground coal mines
- Industrial landfills
- Wastewater treatment
- Suppliers of coal

We plan to further review public comments and other information before finalizing these subparts. Additional discussion of our reasons for not finalizing these particular source categories at this time can be found in the individual subsections in Section III of this preamble.

2. Scope of Source Categories Covered

Comment: Several commenters suggested that the scope of reporting and the source categories covered should be broader. Some indicated that the rule should require reporting of net rather than gross emissions, including reporting of offset projects. In addition, some of the comments suggested requiring reporting of emissions and sequestration from forestry practices.

Response: EPA selected the source categories required to report under the rule after considering the language of the Appropriations Act, the accompanying explanatory statement, the CAA, and EPA's experience in developing the U.S. GHG Inventory. The Appropriations Act referred to reporting ''in all sectors of the economy,'' and the explanatory statement directed EPA to include ''emissions from upstream production and downstream sources to the extent the Administrator deems it appropriate.'' EPA interpreted this to mean direct emissions from facilities over a certain threshold as well as the emissions associated with fuel or industrial gases when completely combusted or used, but not necessarily project-based reductions or sequestration.[14] Calculation and reporting of net emissions (emissions at a facility less any sequestration occurring at the facility) was determined to be outside of the scope of this rule.

In selecting source categories, EPA considered all anthropogenic sources of GHG emissions (those produced as a result of human activities) included in the U.S. GHG Inventory and reviewed the 2006 IPCC Guidelines for National Greenhouse Gas Inventories and existing voluntary and regulatory GHG reporting programs for additional source categories that might be relevant. EPA systematically reviewed the list of source categories developed from the U.S. GHG Inventory and the IPCC guidance to ensure the inclusion of those that emit the most significant amounts of GHG emissions while minimizing the number of reporters. Some sources were deemed inappropriate for inclusion in this rule for a variety of reasons including the current ability to monitor and verify the emissions or products with sufficient accuracy and consistency. For further discussions of sources included and excluded please see Section IV.B of the preamble to the proposed rule (74 FR 16465). In total, the rule is estimated to

[14] For the discussion of the CAA authority to collect these data, *see* Section II.Q of this preamble. Also see the relevant source category sections within Section III of this preamble.

cover approximately 85 percent of U.S. GHG emissions.

With respect to emissions and sequestration from agricultural sources and other land uses, the rule does not require reporting of emissions or sequestration associated with deforestation, carbon storage in living biomass or harvested wood products. These categories were excluded because currently available, practical reporting methods to calculate facility-level emissions for these sources can be difficult to implement and can yield uncertain results. Currently, there are no direct GHG emission measurement methods available except for research methods that are very expensive and require sophisticated equipment. Limited modeling-based methods have been developed for voluntary GHG reporting protocols which use general emission factors, and large-scale models have been developed to produce comprehensive national-level emissions estimates, such as those reported in the U.S. GHG Inventory report. To calculate emissions or sequestration using emission factor or carbon stock exchange approaches, it would be necessary for landowners to report on management practices and a variety of data inputs. The activity data collection and emission factor development necessary for emissions calculations at the scale of individual reporters can be complex and costly. Due to the current lack of reasonably accurate facility-level emissions/stock change factors and the ability to accurately measure all facility-level calculation variables at a reasonable cost to reporters, the reporting of emissions and sequestration associated with deforestation and carbon sequestration from forestry practices was excluded as a source category.

While this reporting rule does not require reporting by facilities or suppliers in every source category, the U.S. GHG Inventory does provide national estimates of emissions from all U.S. anthropogenic GHG sources. In the case of land-based emissions, this includes all emissions by sources and removals by sinks on lands that are managed. The Inventory is prepared annually by EPA, in collaboration with other Federal agencies, and is an impartial, policy-neutral report that tracks annual GHG emissions at the national level and presents historical emissions from 1990 to 2007. The Inventory also calculates carbon dioxide emissions that are removed from the atmosphere by ''sinks,'' such as through the uptake of carbon by forests, vegetation, and soils.

Offsets projects are of interest to many stakeholders because they could be an important component of a potential future cap and trade system. Some commenters requested EPA to include accounting methods for offsets in this reporting rule. We believe that this issue is beyond the scope of this rulemaking and the Congressional request that initiated it. However, EPA will continue to monitor policy needs and developments in the future and is prepared to initiate additional reporting efforts at the appropriate time.

3. Reporting by Both Upstream and Downstream Sources

Comment: Some commenters were concerned that requiring reporting by both fuel and industrial GHG suppliers (upstream sources) and direct emitters (downstream sources) results in double counting of GHG emissions and could lead to overestimation of emissions. Some commenters thought reporting by both upstream and downstream sources was duplicative, confusing, unnecessary, or burdensome and recommended the rule be revised to eliminate double reporting. Other commenters agreed with EPA's proposed selection of source categories to report and that reporting by upstream sources and downstream sources is needed to inform development of GHG policies and programs.

Response: This rule responds to a specific request from Congress to collect data on GHG emissions from both upstream production and downstream sources, as appropriate. The rule requires reporting by facilities that directly emit GHGs above the selected threshold as a result of combustion of fuel or industrial processes (downstream sources). The majority of these reporters are large facilities in the electricity generation and industrial sectors. The rule also requires upstream suppliers of fossil fuels and industrial GHGs to report the GHG emissions that could be emitted from combustion or use of the quantity of fuels or industrial gases supplied into the economy. In many cases, the fossil fuels and industrial GHGs supplied by producers and importers are used and ultimately emitted by a large number of small sources. To cover these direct emissions would require reporting by hundreds or thousands of small facilities. To avoid this impact, the rule does not include all of those emitters but instead requires reporting by the suppliers of industrial gases and suppliers of fossil fuels.

The data collected under this rule are consistent with the appropriations language and provide valuable information to EPA and stakeholders in the development of climate change policy and programs. Potential policies such as low carbon fuel standards can only be applied upstream, whereas end-use emission standards can only be applied downstream. Data from upstream and downstream sources would be necessary to formulate and assess the impacts of such potential policies. Eliminating reporting by either upstream sources or downstream sources would not satisfy EPA's data needs and policy objectives of this rule.

EPA acknowledges that there is inherent double reporting of emissions in a program that includes both upstream and downstream sources. However, as discussed in Sections I.D and IV.B of the preamble to the proposed rule (74 FR 16448, April 10, 2009) EPA does not intend to use emissions data collected by this rule as a replacement for the national emission estimates found in the annual Inventory of GHG emissions.

E. Summary of Comments and Responses on Thresholds

This section contains a brief summary of major comments and responses on EPA's approach and rationale for selection of reporting thresholds. *See* sections III.C through PP of this preamble for summaries of comments and responses on specific threshold analyses for the individual source categories contained in 40 CFR part 98, subparts C through PP. A large number of comments were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Selection of Reporting Thresholds, Greenhouse Gases, and De Minimis Provisions.''

Comment: Many commenters supported the proposed threshold of 25,000 metric tons of CO_2e per calendar year. These commenters generally agreed that the 25,000 metric ton threshold level achieves a reasonable balance between the percentage of national emissions covered and the number of reporters, resulting in a sufficiently comprehensive dataset while minimizing the impact on small facilities. Some also commented that this threshold is consistent with other existing GHG programs or likely future programs. Some commenters supported a 100,000 metric ton CO_2e threshold because they believe this level covers an appropriate percentage of national GHG emissions while easing the reporting burden on industry. Some commenters supported an emission threshold of 10,000 metric tons CO_2e to enable collection of emissions data for smaller sources. Some of these commenters also noted that a 10,000 metric ton CO_2e threshold is more appropriate in order to monitor leakage of emissions to smaller sources (since 25,000 metric tons of CO_2e is a likely threshold for future emissions reductions mandates). Some commenters suggested quantitative evaluation of intermediate threshold options in addition to the four evaluated by EPA (1,000; 10,000; 25,000; and 100,000); several of these suggested EPA analyze a threshold of 50,000 metric tons CO_2e to reduce the number of reporting facilities.

Response: As described in the preamble to the proposed rule (74 FR 16448, April 10, 2009), EPA considered four threshold levels, as well as capacity-based thresholds where appropriate, and we proposed a threshold of 25,000 metric tons of CO_2e for many source categories, and capacity-based or ''all in'' thresholds for other categories. Based on comments received, we reexamined the threshold analyses both in general and for each industry, taking into account additional data provided, and we considered whether there were reasons to develop different thresholds in specific industry sectors. The specific elements of these analyses are discussed in the relevant source category discussions in this preamble and the accompanying ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments'' volumes for each source category. At the general level, we also considered non-quantitative factors, such as consistency with State and other programs (the majority have established thresholds for GHG reporting at 25,000 metric tons or lower, such as 10,000 or 5,000 metric tons), and the need to select a threshold level that best satisfies the objective of the reporting rule to collect a national data set that is sufficiently comprehensive for use in analyzing a range of GHG policies and programs.

From these analyses, we concluded that a 25,000 metric ton threshold suited the needs of the reporting program by providing comprehensive coverage of emissions with a reasonable number of reporters, thereby creating the robust data set necessary for the quantitative analyses of the range of likely GHG policies, programs and regulations. Moreover, the 25,000 metric ton threshold covers similarly sized sources as covered by many current CAA programs (e.g., NSPS applies PM emissions limits to oil-fired and coal-fired units larger than 30 mmBtu per hour).[15] And, as mentioned previously, this level is consistent with (or higher than) the majority of other GHG reporting programs. Furthermore, having a uniform threshold [16] was an equitable approach because like facilities could be compared across sectors and no one industry would be disproportionately affected or subjected to a lower or higher threshold. A uniform threshold is also essential for evaluating potential policies and programs that could have a single emissions threshold across source categories (e.g., PSD), and simplifies the applicability determination for facilities that emit GHGs from more than one source category under the rule.

As discussed in Section IV.C of the preamble to the proposed rule (74 FR 16448, April 10, 2009), we considered four potential thresholds (the range of 1,000 to 100,000 metric tons of CO_2e) and from our analysis and the comments we concluded we had enough information to select an appropriate threshold for the final rule and that detailed quantitative analyses of additional intermediate thresholds would not change EPA's decision. For example, in reviewing our threshold analyses, we determined that the intermediate options between 25,000 and 100,000 metric tons would not provide an alternative threshold that substantially reduced the number of the reporters relative to other options considered or substantially improved the cost effectiveness. (*See* ''Review of Threshold Analyses'' memorandum in docket EPA–HQ–OAR–2008–0508.) Based on our proposal analysis on the data available, we saw that the majority of the affected facilities or suppliers had emissions either considerably above or below 25,000 metric tons CO_2e per year. (As previously explained, supplier GHG quantities represent the emissions that could be released when the products they supply are combusted or used.) The selected threshold took into account our finding that while a threshold other than 25,000 metric tons of CO_2e might appear to achieve an appropriate balance between the number of facilities and emissions covered for a limited number of source categories, there are several additional reasons for selecting the threshold of 25,000 metric tons of CO_2e per year.

The lower threshold alternatives that we considered were 1,000 metric tons of CO_2e per year, and 10,000 metric tons of CO_2e per year. At proposal, we explained that we did not select either of these thresholds because although both broaden national emissions coverage, they do so by disproportionately increasing the number of affected facilities. With the data available at proposal and from the comment period, we remain convinced that the 1,000 metric ton CO_2e/year threshold would increase the number of reporters by an order of magnitude, thus changing the focus of the program from large to small emitters and imposing reporting costs on tens of thousands of small businesses that in total would amount to less than 10 percent of national GHG emissions. Our analysis indicates that a 10,000 metric ton CO_2e/yr threshold would approximately double the number of reporters, but would only increase national emissions coverage by one percent. (See the Regulatory Impacts Analysis for the final rule for the estimated number of facilities and GHG emissions covered by the alternative thresholds examined.) While some proposals (e.g., WCI and H.R. 2454, American Clean Energy and Security Act) contain a 10,000 metric ton threshold for reporting, EPA concluded for policy evaluation purposes, the 25,000 metric ton threshold more effectively targets large industrial emitters and suppliers, covers approximately 85 percent of U.S. emissions, and minimizes the burden on smaller facilities.

We also reviewed the 100,000 metric tons of CO_2e per year as an alternative threshold but concluded that it fails to satisfy key objectives. It excludes a number of emitters in certain source categories such that the emissions data would not adequately cover key sectors of the economy. At 100,000 metric tons CO_2e per year, reporting for some large industry sectors would be rather significantly fragmented, resulting in an incomplete understanding of direct emissions from that sector. We concluded that this threshold would not sufficiently cover the types of facilities that are typically regulated under the CAA and would be inadequate for the intended use of analyzing potential policies and developing future CAA programs.

Based on our review, EPA has determined that the selected 25,000 metric ton CO_2e threshold will cover many of the types of facilities and suppliers typically regulated under the CAA, while appropriately balancing

[15] As explained in section II.A of this preamble, facilities that only have stationary combustion units as their only source of emissions and have units with an aggregate maximum heat input of less than 30 mmbtu are not included in this rule.

[16] Although the thresholds were expressed in different ways (e.g., ''all-in'', annual emissions) most corresponded to, or were consistent with, an annual facility-wide emission level of 25,000 metric tons of CO_2e.

emission coverage and burden. At this threshold, EPA will be able to evaluate the effects of a number of options and policies that could address GHG emissions without placing an undue burden on a large number of smaller facilities and sources. In addition, this threshold level is largely consistent with many of the existing GHG reporting programs and different legislative proposals in Congress. Furthermore, many industry stakeholders that EPA met with and the majority of public commenters, representing a wide variety of stakeholders, expressed support for a 25,000 metric ton CO_2e threshold, agreeing with the Agency's assessment of coverage.

F. Summary of Comments and Responses on Level of Reporting

This section contains a brief summary of major comments and responses on the level of reporting. A large number of comments were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Selection of Source Categories to Report and Level of Reporting.''

Comment: Many commenters supported facility-level reporting rather than corporate-level reporting. The reasons they gave included: Facility-level reporting is consistent with most air rules and permitting programs, environmental managers are used to facility-level reporting, facility-level data would be needed to implement likely future regulatory programs such as a cap and trade program, this approach is simpler to implement and minimizes administrative burden, a facility's corporate status can change during the year, and tying data to physical sources makes emissions easier to track and monitor over time. On the other hand, several commenters favored corporate-level reporting. The reasons they gave included: The effect of GHG emissions is global, therefore the location where the GHGs are emitted is not important; various other GHG programs require corporate-level reporting and have mechanisms for handling ownership changes; the overall carbon footprint of a corporation is important; a company's entire emissions should be reported, not just those facilities that are above a threshold; and facility-level data are more likely to be CBI.

Response: In response to comments, EPA reviewed our initial views outlined in Sections IV.D and V of the proposal preamble (74 FR 16448, April 10, 2009) in light of our data needs under the CAA, our interpretation of the Congressional request, and the feedback received. Based on these considerations, we determined that the final rule will retain the same reporting level as the proposed rule. Facility-level reporting is required, with the exception of some supplier source categories (e.g., importers of fuels or industrial GHGs or manufacturers of motor vehicles and engines). If a facility is covered by the rule, the reporter must report the facility's GHG emissions from all source categories for which the rule contains GHG emission methods. The total emissions for the facility are reported, as well as emissions broken out by source category within the facility. Subparts for some source categories specify further breakout of emissions by process line or unit.

We retained this approach because the purpose of this rule is to collect data from suppliers and from facilities with direct GHG emissions above selected thresholds for use in analyzing, developing, and implementing potential future CAA GHG policies and programs. Facility-level data are needed to support analyses of some types of potential GHG reduction programs, such as NSPS. The data collected from facility-level reporting under this rule will improve our ability to formulate a set of climate change policy options and to assess which facilities and industries would be affected by the options and how they would be affected. (Note, we expect that similarly, facility-level data will also be useful to States, the public, and other stakeholders to formulate State and regional programs and track emission trends over time.) Reporting by individual facilities is also consistent with most existing air regulatory such as ARP, NSPS and national emission standards for hazardous air pollutants (NESHAP), and permitting programs. Many facility environmental managers are already experienced with facility-level emissions reporting under such programs and can likewise submit reports under the mandatory GHG reporting rule.

Corporate-level reporting was not selected because corporate reporting without facility-specific details would not provide sufficient data to assess many potential CAA GHG policies and programs. EPA understands that some corporate-level GHG reporting programs have mechanisms to establish reporting responsibilities under complex and changing ownership situations, but we find corporate-level reporting overly complex for this rulemaking given that facility level data are needed, and it is simpler to place reporting responsibility directly on individual facilities. We note that while EPA requires facility-level reporting, it is up to the facility owners and operators to select the designated representative who will submit the report for a facility, and reporters can also establish any internal corporate review processes they deem appropriate.

While EPA agrees with the commenters who indicated that information on corporate carbon footprints is useful for various purposes, collection of such information is outside the scope of this rulemaking. With that said, we are exploring options for adding additional data elements to the reports, such as name of parent company and NAICS code(s), to allow easier aggregation of facility-level data to the corporate level under this program. EPA expects to subject any additional requests to notice and comment rulemaking. In any event, we expect that the facility-level data collected under this rule will be useful for programs that request or require corporate reporting. But, as explained in Sections I.D and I.E of this preamble, this reporting rule is one action to respond to a specific request from Congress. Various other Federal and State programs are collecting and will continue to collect corporate-level data on direct and indirect emissions, energy efficiency, and other data as part of a broad array of climate change initiatives.

For the response to the commenters' concern about CBI, see Section II.R of this preamble.

G. Summary of Comments and Responses on Initial Reporting Year and Best Available Monitoring Methods

This section contains a brief summary of major comments and responses on the initial reporting year. A large number of comments were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Initial Year of Reporting, Duration of the Reporting Program, and Provisions to Cease Reporting.''

Comment: The proposed rule included reporting of calendar year 2010 emissions in March 2011, which would require reporters to collect data starting on January 1, 2010. The preamble to the proposed rule also discussed options of allowing reporting of best available data for 2010, or delaying reporting by one year (64 FR 16471, April 10, 2009). Many industries with source categories covered by the proposed rule commented that a data collection start date of January 1, 2010, does not provide sufficient time to review the final rule, purchase and install required monitoring equipment, train staff, and develop internal electronic data management and recordkeeping systems needed to comply with the rule. Many indicated that they do not currently have all the meters and monitoring equipment required by the rule. Most of these commenters strongly stated that calendar year 2011 should be the first reporting year. Many of them also stated that if EPA decides data collection must begin in 2010, a best available data approach should be allowed for calculating and reporting 2010 emissions.

Conversely, Congressional inquiries and a large number of public commenters including States, NGOs, and the general public, emphasized that data collection must start in 2010 because time is of the essence for developing and implementing GHG policies and programs. These commenters urged EPA to require reporting of calendar year 2010 GHG emissions and not to delay data collection until calendar year 2011.

Some of the commenters made suggestions about the types of data and methods that could be allowed if EPA chose to use a best available data approach for 2010.

Response: EPA carefully reviewed input from all commenters with the goal of balancing the urgent need for data against the legitimate concerns raised regarding timing. As a result, we have revised the approach for the final rule. The final rule requires data collection for calendar year 2010, but has been changed since proposal to allow use of best available monitoring methods for the first quarter of 2010.

Schedule. EPA decided to require reporting of calendar year 2010 emissions because the data are crucial to the timely development of future GHG policy and regulatory programs. In the Appropriation Act, Congress requested EPA to develop this reporting program on an expedited schedule, and Congressional inquiries along with public comments reinforce that data collection for calendar year 2010 is a priority. Delaying data collection until calendar year 2011 would mean the data would not be received until 2012, which would likely be too late for many ongoing GHG policy and program development needs.

However, EPA understands that because the final rule is not being promulgated until fall of 2009, facilities that do not already have the monitoring systems required by the rule in place might not have time to install and begin operating them by January 1, 2010. Under the schedule in the Appropriations Act, the final rule would have been signed at the end of June 2009, which would have allowed approximately six months to prepare for data collection in January 2010. Given the delay in promulgating the rule, there is less time between signature of the rule and a January 1, 2010 start date. In light of this fact, and the industry comments indicating that facilities do not currently have all of the required monitoring systems, EPA has decided to provide flexibility by establishing a best available monitoring methods option for the first quarter of calendar year 2010. This approach will provide time comparable to what would have occurred had EPA met the schedule in the Congressional request. We will post the rule on EPA's Web site soon after signature, allowing reporters to see the final requirements and begin compliance planning even before the rule is published in the **Federal Register**.

For the time period of January 1 through March 31, 2010, the rule allows use of best available monitoring methods for parameters that cannot reasonably be measured according to the monitoring and QA/QC requirements of the relevant subpart. Starting no later than April 1, 2010, the reporter must begin following all applicable monitoring and QA/QC requirements of this part, unless they submit an extension request showing that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by the specified date and EPA approves the request. EPA may approve such requests for a set time period, but will not approve the use of best available methods beyond December 31, 2010. See the paragraph heading ''Extension Request Process'' near the end of this response for further details.

EPA has concluded that the time period allowed under this schedule (including the provision for facility-specific requests) will allow facilities that do not currently have the required monitoring systems sufficient time to begin implementing the monitoring methods required by the rule. In general, the required monitors, such as flow meters, are widely available and are not time consuming to install. By allowing the additional time, many facilities may also be able to install the equipment during other planned (or unplanned) process unit downtime, thus avoiding process interruptions.

Definition of Best Available Monitoring Methods. In determining methods that would be allowed under a best available monitoring methods approach, EPA considered the goal of collecting consistent data to provide information of sufficient quality to inform policy and program development, while recognizing that not all facilities may be able to implement the full monitoring methods required by the rule by January 2010. We reviewed the public comments as well as the California Air Resources Board (CARB) mandatory reporting rule, and we considered options falling between full flexibility to use any method and the full requirements of EPA's mandatory reporting rule.

The least stringent approach would be to allow facilities to calculate GHG emissions using any data, methods, calculation procedures, or emission factors they choose during the best available monitoring period and submit minimal supporting data. This approach would provide maximum flexibility to industry, but EPA did not select this approach because the usefulness of the collected data would be questionable given that it would be obtained using inconsistent methods and it could not be verified with sufficient confidence. Instead, EPA developed a hybrid approach that falls between full flexibility and implementation of full monitoring requirements in January 2010. Under the final rule, during January 1, 2010, through March 31, 2010, reporters may use best available monitoring methods for any parameter (e.g., fuel use, daily carbon content of feedstock by process line) if that parameter cannot reasonably be measured following the monitoring and QA/QC requirements of a relevant subpart. The reporter must use the calculation procedures and equations in the ''Calculating GHG Emissions'' sections of each relevant subpart, but may use the best available monitoring method for any parameter for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2010. Best available monitoring methods include the following:

- Monitoring methods currently used by the facility that do not meet the specifications of a relevant subpart.
- Supplier data.
- Engineering calculations.
- Other company data.

Reporters must submit an annual GHG report for 2010. This calendar year 2010 report (submitted March 31, 2011) includes the same information as in subsequent years, but also requires brief descriptions of each best available monitoring method used, the parameter measured using that method, and the time period during which the method was used.

EPA selected this approach because it is responsive to commenters' concerns that monitoring equipment cannot be installed by January 1, 2010, while also ensuring timely submission of more consistent and verifiable data than the alternatives. We have concluded that the data will be more consistent because all reporters will use the same basic emissions calculation equations that are in the rule, with best available inputs, rather than the wide range of calculation methods that would likely be used under a full flexibility approach. Furthermore, the selected approach requires reporting of sufficient information for EPA to verify the emissions data. We have therefore determined that this approach for collection and reporting of the calendar year 2010 data will fulfill the objectives of this reporting rule.

It should also be noted that, like the proposed rule, the final rule allows facilities that must report only emissions from general stationary fuel combustion equipment (and do not have other covered source categories) to determine calendar year 2010 emissions using any of the methods (tiers) in 40 CFR part 98, subpart C, and submit an abbreviated GHG report. Full reporting starts with calendar year 2011. This allows such facilities, which are less likely to have experience with emissions monitoring and reporting, an extra year to begin full reporting using all the procedures required by the rule.

Extension Request Process. We expect that the vast majority of facilities will begin complying with the full monitoring requirements of the rule no later than April 1, 2010, and will not require or be granted an extension. However, EPA is providing facilities with specific circumstances an opportunity to request an extension in the use of best available monitoring methods. EPA will review extension requests to determine whether they should be approved. We envision that extensions will apply primarily to situations when needed monitoring instrumentation could not be obtained within the timeframe despite good faith efforts by the facility, or when installation of monitoring instrumentation would require a process unit shutdown that could not feasibly be scheduled prior to April 1, 2010.

Timing. Reporters must submit extension requests to EPA no later than 30 days after the effective data of the GHG reporting rule. EPA intends to review each submitted request and may approve or disapprove the requests. EPA may approve the request for a specified time period, but will not approve the use of best available methods beyond December 31, 2010. If EPA disapproves an extension request, then the reporter is required to implement the full monitoring methods required by the rule by April 1, 2010.

Content of Request. Requests must contain the following information:

- A list of specific monitoring instrumentation for which the request is being made and the locations where each piece of monitoring instrumentation will be installed.
- Identification of the specific rule requirements (by rule subpart, section, and paragraph numbers) for which the instrumentation is needed.
- A detailed description of the reasons why the needed equipment could not be obtained and installed before April 1, 2010.
- If the reason for the extension is that the equipment cannot be purchased and delivered by April 1, 2010, include supporting documentation such as the date the monitoring equipment was ordered, investigation of alternative suppliers and the dates by which alternative vendors promised delivery, backorder notices or unexpected delays, descriptions of actions taken to expedite delivery, and the current expected date of delivery.
- If the reason for the extension is that the equipment cannot be installed without a process unit shutdown, include supporting documentation demonstrating that it is not possible to isolate the equipment, piping, or line and install the monitoring instrument without a full process unit shutdown. Also include the date of the most recent process unit shutdown, the frequency of shutdowns for this process unit, and the date of the next planned shutdown during which the monitoring equipment can be installed. If there has been a shutdown or if there is a planned process unit shutdown between promulgation of this rule and April 1, 2010, include a justification of why the equipment could not be obtained and installed during that shutdown.
- A description of the specific actions the facility will take to obtain and install the equipment as soon as reasonably feasible and the expected date by which the equipment will be installed and operating.

Approval Criteria. EPA will approve a request if it contains all of the information required by the rule and if it demonstrates to the Administrator's satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by April 1, 2010.

For example, EPA is likely to approve a request for an extension if the documentation provided by the reporter shows that they ordered monitoring equipment in a timely manner, attempted to find a supplier who could deliver it in time, and could not control the fact that the equipment was not received for installation prior to April 1, 2010.

If a reporter requests an extension because equipment cannot be installed without a process unit shutdown, EPA is likely to approve such a request if the documentation clearly demonstrates why it is not feasible to install the equipment without a process unit shutdown, shows there is not a planned shutdown (and has not been a shutdown) prior to April 1, 2010, during which the monitoring instrument could be installed. There are many locations where monitors can be installed without a process unit shutdown, because there is often some redundancy in process or combustion equipment or in the piping that conveys fuels, raw materials and products. For example, many facilities have multiple combustion units and fuel feed lines such that when one combustion unit is not operating they can obtain the needed steam, heat, or emissions destruction by using other combustion devices. Some facilities have multiple process lines that can operate independently, so one line can be temporarily shut down to install monitors while the facility continues to make the same product in other process lines to maintain production goals. If a monitor needs to be installed in a section of piping or ductwork, it can be possible in some cases to isolate a line without shutting down the process unit (depending on the process configuration, mode of operation, storage capacity, etc.). If the line or equipment location where a monitor needs to be installed can be temporarily isolated and the monitor can be installed without a full process unit shutdown, it is less likely EPA will approve an extension request.

While there might be other unique facility-specific situations for which an extension might be granted, EPA expects few of these. There have been several changes to the rule since proposal that would reduce the need for extensions. For example, fewer source categories are included in the final rule; changes have been made to the monitoring requirements of some rule subparts to allow more flexibility in monitoring methods; and provisions have been added to the general stationary fuel combustion, petroleum refineries, and petrochemical productions subparts allowing facilities additional time to perform some monitor calibrations. These changes address many of the specific situations about which commenters raised concerns.

It is highly unlikely we would approve extension requests for parameters that are measured by periodic sampling and analyses. Facilities should be able to make arrangements to collect periodic samples and send them off-site for analyses (if they don't have on-site analytical capabilities) without the need for an extension. Similarly, extensions for design of electronic recordkeeping systems seem unnecessary. Many facilities already have electronic recordkeeping systems that can be altered to keep the records needed for this rule. Furthermore, reporters can keep the specified records in any type of hard copy or electronic format they choose, as long as it is in a form suitable for expeditious inspection and review.

H. Summary of Comments and Responses on Frequency of Reporting and Provisions To Cease Reporting

This section contains a brief summary of major comments and responses on the frequency of reporting and on whether reporters should be allowed to stop submitting annual reports if emissions are reduced below a threshold level. A large number of comments were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Initial Year of Reporting, Duration of the Reporting Program, and Provisions to Cease Reporting'' and ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart A: Applicability and Reporting Schedule.''

1. Provisions To Cease Reporting if Emissions Decrease

Comment: The majority of public commenters favored annual reporting as opposed to more or less frequent reporting. Many commenters, especially industrial facilities required to report under the rule, objected to the ''once in always in'' reporting approach in the proposed rule and requested a mechanism to stop reporting if emissions fall below the 25,000 metric tons CO_2e per year annual threshold. Others suggested a level different from 25,000 metric tons CO_2e per year to cease reporting. Some commented that the lack of such a mechanism is a disincentive to reduce facility emissions. Conversely, other commenters supported the proposed once in always in approach in order to create a consistent, long term data set covering the same population of facilities over time that could be used to track trends and understand factors that influence emission levels.

Response: After reviewing the comments, EPA has not changed the frequency of reporting since the proposed rule. Affected facilities and suppliers must submit annual GHG reports. Facilities with ARP units that report CO_2 emissions data to EPA on a quarterly basis would continue to submit quarterly reports as required by 40 CFR part 75, in addition to providing the annual GHG reports. We have determined that annual reporting is sufficient for policy and regulatory development. It is also consistent with other existing mandatory and voluntary GHG reporting programs at the State and Federal levels (e.g., The Climate Registry (TCR), several individual State mandatory GHG reporting rules, EPA voluntary partnership programs, the DOE voluntary GHG registry).

In response to comments on ''once in, always in,'' however, EPA has added provisions to allow facilities and suppliers to stop submitting annual reports under certain conditions. These provisions apply to facilities and suppliers regardless of their applicability threshold as it is based on the annual report.

- Under the first provision, if any facility's annual GHG reports demonstrate emissions of less than 25,000 metric tons of CO_2e per year for five consecutive years, they can cease submitting annual reports. Similarly, if any supplier's annual reports demonstrate that the products supplied equate to less than 25,000 metric tons of CO_2e per year for five consecutive years, they can cease submitting annual reports.
- Under the second provision, if any facility's or supplier's annual GHG reports demonstrate emissions of less than 15,000 metric tons CO_2e per year for three consecutive years, they can cease submitting annual reports.

In either case, before they can stop reporting, the facility or supplier must submit a notification to EPA that announces the cessation of reporting and explains the reasons for the reduction in emissions so EPA can understand the reason for the decrease in emissions to help aid in evaluating emission reduction options across the industry.

If emissions subsequently increase to 25,000 metric tons of CO_2e or more in any calendar year, the facility or supplier must again begin annual reporting. Importantly, although a source may not know its emissions (or quantities supplied) exceeded the reporting threshold until later in the year, the requirements of the rule apply as of January 1, unless the increase is a result of a physical or operational change covered by 40 CFR 98.3(b). Thus sources close to the threshold should consider monitoring their emissions according to requirements of 40 CFR part 98 if they determine there is a chance they will meet or exceed the threshold. EPA is developing tools and guidance to assist facilities and suppliers in assessing whether the requirements of the rule apply to them.

EPA concluded that adding the provisions to allow cessation of reporting balances the need for a complete dataset with the burden of continued annual reporting by facilities where there has been a change that has consistently reduced emissions (or supplier quantities) below 25,000 metric tons CO_2e. This approach rewards actions taken to reduce emissions and reduces the reporting burden. It is consistent with other reporting programs, such as the CARB mandatory reporting rule and the WCI program, both of which have mechanisms to allow facilities to cease reporting if their emissions are below a specified threshold for multiple consecutive years.

For the first provision, EPA selected 25,000 metric tons CO_2e per year because it is the same as the general applicability threshold for this rule.[17] We selected a 5-year period, instead of a shorter time frame, because it allows reporters that consistently report less than 25,000 metric tons CO_2e to stop reporting, but avoids the situation where a facility or supplier near this level would be constantly moving in and out of the reporting program due to small variations from one year to the next. Because this reporting rule is based on actual rather than potential emissions, such a situation would make tracking of facilities and analyses of trends difficult.

The second provision (cease reporting if emissions were below 15,000 metric tons for three consecutive years) was added to reduce the duration of reporting for facilities and suppliers that reduce emissions to well below 25,000 metric tons. In such cases, a 5-year period is longer than necessary to

[17] Applicability thresholds for different source categories are expressed in different ways (e.g., actual emissions, production capacity, ''all-in''), but most correspond to a facility-wide emission level of 25,000 metric tons per year. The provision to cease reporting applies to reporters regardless of the specific applicability threshold that triggered reporting for their facility or supply operation.

demonstrate that annual emissions will remain below 25,000 metric tons per year. If emissions are less than 15,000 metric tons for three consecutive years, it is unlikely that annual variation in emissions would cause the facility or supplier to exceed the threshold of 25,000 metric tons per year. The shorter time period provides an incentive for facilities that significantly reduce their GHG emissions.

2. Provisions To Cease Reporting Due to Closures

Comment: Several commenters suggested that EPA add a provision to allow closed facilities, or facilities or suppliers that stop operating their GHG-emitting processes, to cease annual reporting.

Response: In response to comments, EPA has added a mechanism to allow facilities or suppliers that close all of their GHG-emitting processes or operations covered by the rule to cease annual reporting. The reporter must submit an annual report covering the calendar year during which the closure occurs. The reporter must also notify EPA that they intend to cease reporting and must certify that all GHG-emitting processes and operations for which there are methods in the rule have been closed. EPA agrees that it does not make sense for closed facilities or facilities that close all of their GHG-emitting processes to continue reporting indefinitely or for the 5-year period needed to demonstrate that emissions are less than 25,000 metric tons CO_2e per year (or the 3-year period needed to demonstrate emissions are less than 15,000 metric tons CO_2e per year). However, notification is required so that we can track facilities and understand why facilities stop reporting. If a facility or supplier that was once subject to the reporting rule and ceased reporting under this provision restarts any of the GHG-emitting processes or operations formerly reported, then they must resume annual reporting regardless of whether they exceed the thresholds in 40 CFR 98.2(a) when they restart. This provision is important so that EPA can consistently track emissions from facilities covered by the rule. If after the restart, annual reports show emissions of less than 25,000 metric tons CO_2e per year for five consecutive calendar years or less than 15,000 metric tons CO_2e per year for three consecutive years, then the facility could be exempt under the separate mechanism discussed in Section II.H.1 of this preamble.

It is important to note that the provision to stop reporting is not intended to apply to seasonal or longer temporary cessation of operation. The mechanism is intended for long-term closure situations. It should also be noted that in order to use this provision to cease reporting, a facility or supplier must close *all* of their processes and operations that are required to report emissions. For example, consider a facility that is required to report process emissions from one or more source categories covered by 40 CFR part 98 and general stationary fuel combustion source emissions. If the facility closes some of the process units subject to the rule but continues to operate other process units covered by the rule or continues to operate stationary fuel combustion sources, then they must continue to submit annual reports until the required annual GHG reports demonstrate emissions of less than 25,000 metric tons of CO_2e per year for five consecutive years (or less than 15,000 metric tons of CO_2e per year for three consecutive years) and the facility qualifies for the separate provisions to stop reporting discussed in Section II.H.1 of this preamble.

I. Summary of Comments and Responses on General Content of the Annual GHG Report

This section contains a brief summary of major comments and responses on the emissions information to be reported under the general provisions (40 CFR part 98, subpart A). See sections III.C through PP of this preamble for summaries of comments and responses on specific reporting requirements for the individual source categories contained in 40 CFR part 98, subparts C through PP. A large number of comments on emission information to report under the general provisions were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart A: Content of the Annual Report, the Abbreviated Emission Report, Recordkeeping, and Monitoring Plan.''

Comment: EPA received a variety of comments on the general content of the annual GHG reports. Some commenters objected to the level of detail required in the annual GHG reports. Some suggested reporting only facility-level emissions and keeping as records more detailed emissions breakouts (e.g., by source category, process line, or unit) and activity data used to calculate emissions. Other commenters supported the proposed general reporting requirements.

Response: After reviewing the comments, we have not made any major changes in the general content of the annual GHG reports since proposal. The final rule requires facilities to report emissions from all source categories at the facility for which methods are defined in the rule. The General Provisions (40 CFR part 98, subpart A) require facilities to report total annual GHG emissions in metric tons CO_2e and to separately present annual mass emissions of each individual GHG emitted from each source category at the facility. Reporting of CO_2e allows a comparison of total GHG emissions across facilities in varying categories which emit different GHGs. Knowledge of both individual gases emitted and total CO_2e emissions maintains transparency, is valuable for future policy and regulatory development, and will help EPA quantify the relative contribution of each gas to a source category's emissions and maintain transparency.

Individual rule subparts for each source category, rather than the General Provisions, identify the specific data elements to be reported for that source category. Comments received on the need for specific data elements are described and responded to in Section III of this preamble and in relevant source category volumes of the ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments''. Where appropriate, the final rule has been modified based on those comments. In general, reporting of such data is required primarily to enable emissions verification and ensure the consistency and accuracy of data collected under this rule. The information is also needed to support analyses of GHG emissions for future CAA policy and program development. Besides total facility emissions, it benefits policy makers to understand: (1) The specific sources of emissions and the amounts emitted by each unit/process to effectively interpret the data, and (2) the effect of different processes, fuels, and feedstocks on emissions. Many of these data are already routinely monitored and recorded by facilities for business reasons. Further discussion of the selection of general reporting requirements is contained in Section IV.G of the proposal preamble (74 FR 16472, April 10, 2009). Other responses to comments on the reporting requirements in 40 CFR Part 98, Subpart A, and discussion of some clarifications made to the rule, are contained in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart A: Applicability and Reporting Schedule'', ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart

A: Content of the Annual Report, the Abbreviated Emission Report, Recordkeeping, and Monitoring Plan'', and ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart A: Definitions, Incorporation by Reference, and Other Subpart A Comments''.

J. Summary of Comments and Responses on Submittal Date and Making Corrections to Annual Reports

1. Submittal Date for Annual Report

Comment: Several commenters requested that EPA change the annual submittal date for GHG reports from March 31 to a later date, such as April 30 or June 30. Several commenters stated that March 31 does not provide adequate time for data collection, aggregation and disaggregation, GHG calculations, QA, management review, and certification, and explained that this is a complex process for large industrial sites that have many individual GHG emission sources. Some of these commenters indicated that unexpected issues can arise during GHG emissions calculations and QA that take time to resolve. Some of these commenters suggested a date of June 30 to align this mandatory reporting rule with the submittal dates for other reporting programs such as California Climate Action Registry (CCAR), TCR, Climate Leaders, and Toxic Release Inventory (TRI). Some commented that the same personnel who will prepare the GHG reports are also involved in preparing other EPA mandated reports and that completing multiple reporting activities in the first quarter is a large workload. Other commenters favored the March 31 reporting date so that the data could be disseminated and available for use by policy makers, EPA, States, and the public in a timely fashion.

Response: After reviewing and addressing both general comments and comments received on this issue for specific source categories, and considering the need to balance prompt reporting with the burden on reporters, EPA has determined that the reporting deadline of March 31 allows a sufficient amount of time for compiling, reviewing, certifying, and submitting annual GHG reports. The March deadline will ensure timely collection of the data necessary to inform decisions regarding future GHG policy and program development. Since the data needed to calculate emissions and prepare the report must be collected on an ongoing basis throughout the year, reporters can begin to compile the data for the report and initiate QA activities during the year as the data are collected. Reporters would then only have to compile the most recently collected information, complete the final calculations, and review and certify the annual report after the reporting period has ended. Because the reports required by the rule rely on well-defined calculation methodologies, EPA determined that three months is a sufficient amount of time to complete the report. Moreover, as discussed in Section III of this preamble for the specific subparts, we have made several changes to reporting requirements that will ease burden and further facilitate reporting by March 31. In addition, EPA intends to provide outreach and training on rule requirements and an electronic reporting system that will help expedite report submission.

The March 31 reporting deadline is also consistent with the reporting deadline implemented in 2005 for reporting GHG emissions under the EU Emissions Trading System and is longer than the deadlines allowed for reporting under many other CAA programs. For example, many NESHAPs and NSPSs, including those for large complex industrial facilities such as chemical plants and refineries, require reports of excess emissions and monitoring system performance to be submitted within 30 calendar days of the end of each compliance period. The ARP and Regional Greenhouse Gas Initiative (RGGI) programs, which are established emission cap and trade programs that rely on the same types of data many sources will have to submit under the GHG reporting rule, require facilities to submit their quarterly emissions reports within 30 days of the end of each quarter.

2. Making Corrections to Annual Reports

Comment: Several commenters representing multiple stakeholders suggested the rule should include provisions to submit revised annual reports. Many commented that even with good-faith efforts to follow all the monitoring and reporting requirements, there will likely be unintentional errors that are not discovered by the reporter or by EPA until after an annual report is submitted. Some commenters added that given the stringency of the self-certification provisions and potential penalties involved, reporters need a way to submit corrected data, and some provided examples of other reporting rules that include provisions to submit revised reports.

Response: EPA has addressed this comment in the final rule. We have added a provision in 40 CFR 98.3 that requires the reporters to submit a revised GHG report within 45 days of discovering or being notified by EPA of errors in an annual GHG report. The revised report must correct all identified errors. We agree that it is important for facilities to correct errors, regardless of whether they are discovered by the reporter or by EPA. In order to ensure accurate data for future GHG policies and programs, known errors should be corrected. Furthermore, adding a requirement to submit corrected reports is consistent with other EPA reporting programs, such as ARP and TRI, as well as State and other GHG programs. EPA intends to review the annual GHG reports submitted under this rule by performing electronic data QA checks and a range of other emission verification activities. When we find reporting errors (as we have in ARP and other reporting programs), we will notify reporters of errors and require them to submit revised reports. The time period of 45 days was selected to allow reporters time to retrieve any needed data, perform revised calculations, and resubmit the report. Because data for the calendar year covered by the report has already been collected and must be retained according to the rule, it should be readily available for any reanalyses needed to correct a reporting error. Given that facilities are allowed three months from the end of a reporting period to submit the annual report, revising a report to address a known error would logically require less time and EPA concluded that 45 days is sufficient.

K. Summary of Comments and Responses on De Minimis Reporting

Comment: Some commenters suggested that *de minimis* cutoffs or simplified methods for *de minimis* sources should be provided to be consistent with other programs, such as the California mandatory GHG reporting rule. The commenters argued that it makes sense to focus effort on the significant emissions sources at a facility, rather than spending a lot of effort to precisely calculate emissions from sources that are a small percent of a facility's total emissions.

Response: EPA considered public comments on *de minimis* reporting, both general comments and those received on individual source categories, in addition to the analyses of *de minimis* provisions we conducted at proposal of the rule. Based on these considerations, we concluded that *de minimis* provisions are not necessary for this rule.

As discussed in the preamble to the proposal (74 FR 16448, April 10, 2009), many existing reporting programs require corporate level reporting of all emissions, including emissions from numerous remote facilities and small onsite equipment (e.g., lawn mowers). Other reporting programs require reporting at the facility level but require reporting of emissions from all types of emission sources.[18] These reporting programs recognize that it may not be possible or efficient to specify the reporting methods for every source that must be reported and include *de minimis* provisions to reduce the reporting burden. The *de minimis* provisions included in these programs either allow the reporter to exclude a portion of their emissions (e.g., the DOE 1605(b) voluntary reporting program allows up to three percent of facility-level emissions to be excluded) or allow simplified calculation methods for small sources.

Since reporters must determine the *de minimis* emissions even when reporting is not required, the trend for both mandatory and voluntary reporting programs is to require reporting of all emissions but allow simplified calculation methods for small sources of emissions. Hence, the *de minimis* provisions included in many existing reporting programs are designed to avoid potentially unreasonable reporting burdens. For example, TCR allows reporters to use simplified calculation methods of their own design for calculating up to five percent of their emissions. Some programs recognize that a small percentage of emissions may still represent a large mass of emissions. For this reason, some existing reporting programs include a cap on the mass of *de minimis* emissions. For example, both the California mandatory reporting rule and EU Emissions Trading System cap *de minimis* emissions at 20,000 metric tons CO_2e/year cap. For additional information on the treatment of *de minimis* in existing GHG reporting programs, please refer to the ''Reporting Methods for Small Emission Points (De Minimis Reporting)'' (EPA–HQ–OAR–2008–0508–0048).

In contrast to such existing programs, this rule already avoids burdensome reporting requirements for smaller emissions sources in two ways. First, the rule excludes small facilities through the application of the 25,000 metric tons of CO_2e threshold. As described earlier in this preamble, that threshold appropriately balances the number and size of reporter with the coverage of emissions. The source categories included in the rule are typically for larger sources of emissions. Second, reporters must report only the emissions from sources for which calculation methods are provided in the rule. Calculation methods are generally not included for smaller sources of emissions (e.g., coal piles on industrial sites). In some cases, where a source category includes relatively small sources, the rule provides simplified emissions calculation methods for those sources. For example, reporters may use a default emission factor and heat rate to calculate emissions from small stationary combustion units, rather than the fuel measurements required for larger stationary combustion units. Given that this rule has taken steps to avoid burdensome calculations, we have concluded that *de minimis* reporting cutoffs are not necessary.

Furthermore, *de minimis* cutoffs would compromise the quality of the data collected. The goal of this rule is to collect accurate and consistent data of sufficient quality to inform future CAA policy and regulatory decisions. Allowing sources to report up to 20,000 metric tons CO_2e emissions annually using their own simplified calculation methods (as allowed under some programs) would impact the usefulness of the data. The reported emissions would not be comparable across a given industry because the calculation methods, accuracy and reliability of a portion of the reported emissions would vary substantially from one reporter to another.

In response to comments, we have made several changes to this rule that further reduce any need for a *de minimis* reporting provision. As discussed in Section III of this preamble for individual source categories, we have revised monitoring and reporting requirements to allow simpler GHG calculation methods for many combustion units and other source categories. These changes reduce the reporting burden for various types of small emission sources. Also, as noted earlier in Section II.D of this preamble, there are a number of source categories that are not being finalized at this time. A few of them (e.g., industrial landfills and wastewater) represent the type of emission sources that commenters referenced as *de minimis* at some facilities. EPA is taking some additional time with these source categories, which affects commenters in two ways: (1) Until EPA promulgates a final rule for these source categories, these emissions would not be included in a facility's annual report and (2) EPA can further consider the comments and evaluate our options with respect to the methods for these source categories to ensure the methods adequately address our need for high quality data as well as recognize the commenters' requests for additional flexibility for smaller sources.

L. Summary of Comments and Responses on General Monitoring Approach

This section contains a brief summary of major comments and responses on general monitoring requirements. See sections III.C through PP of this preamble for summaries of comments and responses on specific monitoring requirements for the individual source categories contained in 40 CFR part 98, subparts C through PP. A large number of comments were received on general monitoring requirements covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, General Montoring Approach, the Need for Detailed Reporting, and Other General Rationale Comments.''

Comment: Many commenters favored the general monitoring approach contained in the proposed rule, which is a combination of direct emissions measurement and facility-specific calculations. These commenters agreed that the selected approach results in high quality data and strikes a reasonable balance between data accuracy and cost. Other commenters believed that the approach contained in the proposed rule is overly stringent and costly. They contended that since the data are not being used to demonstrate compliance with a cap and trade program or other regulation with emission limits or emissions reduction requirements, a lower level of accuracy is acceptable, simpler monitoring approaches should be allowed, and/or facilities should have flexibility to choose monitoring methods. Some commenters requested clarification on whether there were accuracy requirements or performance standards for flow monitoring equipment, outside of the accuracy requirements already required for CEMS. Some commenters requested clarification on whether upgrades to CEMS were needed under various circumstances. Some requested additional time for upgrading CEMS or installing and calibrating other equipment such as flow meters.

Response: After reviewing the comments in light of the analysis

[18] For additional information about these programs please see overview of existing programs (EPA–HQ–OAR–2008–0508–0052) and the *de minimis* memo (EPA–HQ–OAR–2008–0508–0048).

presented in Section IV.H of the preamble to the proposed rule (74 FR 16474, April 10, 2009), EPA decided not to change the general monitoring approach from the proposal. In general, the rule requires direct measurement of emissions from certain units that already are required to collect and report data using CEMS under other programs (e.g., ARP, NSPS, NESHAP, State Implementation Plans (SIPs)). In some cases, this may require upgrading existing CEMS that currently monitor criteria pollutants to also monitor CO_2 or add a volumetric flow meter. For facilities with units that do not have CEMS installed, reporters have the choice to either install and operate CEMS to directly measure emissions or to use facility-specific GHG calculation methods. The measurement and calculation methods for each source category are specified in each subpart. As policies and programs evolve and/or particular calculation or monitoring equipment improves EPA will evaluate whether or not to update the methodologies in this rule.

The data collected by the rule are expected to be used in analyzing and developing a range of potential CAA GHG policies and programs. A consistent and accurate data set is crucial to serve this intended purpose. Therefore, the selected monitoring approach that combines direct measurement and facility-specific calculations is warranted even though the rule does not contain any emissions limits or emissions reduction requirements. EPA remains convinced that this approach strikes an appropriate balance between data accuracy and cost. It makes use of existing data and methodologies to the extent feasible, and avoids the cost of installing and operating CEMS at numerous facilities. It is consistent with the types of methods contained in other GHG reporting programs (e.g., the California mandatory reporting rule, WCI, RGGI, TCR, and Climate Leaders). Because this option specifies methods for each source category, it will result in data that are comparable across facilities.

EPA chose not to adopt simplified calculation methods as a general monitoring approach (e.g., using default emission factors) because the data would be less accurate than under the selected option and would not make use of site-specific data that many facilities already have available and refined calculation approaches that many facilities are already using. EPA is not allowing reporters full flexibility to use any method because the accuracy and reliability of the data would be unknown. Because consistent methods would not be used under such an approach, the reported data would not be comparable across similar facilities.

While the general approach is unchanged, it is important to note that EPA has made changes to the General Provisions and to the specific monitoring requirements for particular source categories in response to public comments on the proposal. EPA has added to the General Provisions (40 CFR part 98, subpart A) an accuracy specification of plus or minus five percent for the calibration of flow meters used to collect data for the emissions calculations under this rule. It provides procedures for calculating calibration error, including specific procedures for orifice, nozzle, and venturi flow meters. Given the comments that were submitted regarding concerns on the timing of performing meter calibration, EPA is providing flexibility to reporters subject to certain operational limitations. For example, facilities that operate continuously may postpone calibration until the next scheduled maintenance outage to avoid operational disruptions.

Individual rule subparts for each source category, rather than the General Provisions, contain the specific monitoring methods for that source category. Comments received on the specific methods are described and responded to in Section III of this preamble and in the relevant source category volumes of ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments.'' Where appropriate, the final rule has been modified based on those comments. For example, since proposal, in response to public comments, EPA has made changes to individual subparts of 40 CFR part 98 to clarify when CEMS and CEMS upgrades are required and has made other changes to reduce the monitoring burden. Interested parties are encouraged to review the relevant sections of the preamble and rule. Furthermore, some subparts for which significant monitoring approach comments were received are not included in the final rule and will be finalized later as explained in Section II.D of this preamble. These changes to the rule address monitoring approach concerns raised by some commenters.

Comment: Some commenters expressed concern that duplicative reporting would occur if the rule was interpreted to require a reporter to submit data on general stationary fuel combustion emissions at a facility both under 40 CFR part 98, subpart C and also under one of the other source category subparts that applies to the same facility. Some of them indicated that language used in the source category subparts to reference subpart C was not sufficiently clear and consistent. Other commenters indicated the proposed rule was not clear about whether CEMS can be used to report combustion emissions, process CO_2 emissions, or combined emissions.

Response: EPA reviewed each subpart in light of these comments and acknowledges that the proposed rule language referencing 40 CFR part 98 subpart C and the language discussing the of CEMS was inconsistent between subparts and was not always clear. EPA has revised the final rule to clarify our intent.

As indicated by the commenters, many manufacturing facilities are subject to one of the source category subparts and also to the general stationary fuel combustion subpart. For most facilities, emissions from stationary fuel combustion sources (e.g., boilers or engines) are emitted from separate equipment and through separate stacks/emission points than process GHG emissions covered by 40 CFR part 98, subparts E through GG. We have edited the rule to make it clear that in such cases, the reporter would report stationary fuel combustion emissions under 40 CFR part 98, subpart C, and they would report process GHG emissions under each applicable source category subpart.

We have further clarified those source category subparts that require reporting of process CO_2 emissions. We have made it clear that the reporter can elect to monitor and report process CO_2 emissions by either: (1) Installing and operating CEMS and following the Tier 4 methodology in 40 CFR part 98, subpart C, or (2) using the source category-specific monitoring and calculation procedure specified in the subpart. In either case, process CO_2 emissions would be reported under the source category subpart. The source category subparts have also been revised to specify that if process CO_2 emissions are comingled with and emitted through the same stack as emissions from combustion units or process equipment required to use CEMS, than the reporter must use the CEMS and follow the Tier 4 methodology to report combined emissions from the common stack under the specified subpart. This approach makes sense for comingled emissions because CEMS accurately measure total stack CO_2 emissions and the reporter would not be able to accurately separate the fraction of the CO_2 emissions that came from the combustion units and process emission points that are comingled in the same stack.

Source categories with direct-fired equipment (e.g., kilns, furnaces) present a special situation. Examples include cement production, glass production, lead production, lime manufacturing, and soda ash manufacturing. In direct-fired units, fuel combustion emissions and process emissions are both generated within the kiln or furnace and are always emitted together. If CEMS are used on such units, the CEMS will always be measuring combined combustion and process emissions. The language regarding CO_2 reporting and use of CEMS for these source categories has been clarified and harmonized to reflect this situation.

- For kilns or furnaces in these source categories that have CEMS in place and meet specified conditions, the reporter must use the CEMS and follow Tier 4 methodology to determine combined process and combustion CO_2 emissions. The combined emissions are reported under the relevant source category subpart (e.g., for cement production, combined combustion and process emissions from a kiln with a CEMS would be reported under 40 CFR part 98, subpart H, Cement Production).
- For other kilns or furnaces in these source categories, the reporter has the choice to (1) install and operate CEMS to measure combined process and combustion CO_2 emissions, or (2) calculate process CO_2 emissions using the source category-specific monitoring and calculation procedures contained in the subpart. If reporters don't have CEMS and choose the source category-specific calculation approach, then they report process CO_2 emissions under the relevant source category subpart, and report combustion emissions under 40 CFR part 98, subpart C (general stationary fuel combustion).

See the sections for the relevant source categories in Section III of this preamble for summary and discussion of the specific monitoring and reporting requirements for each source category.

M. Summary of Comments and Responses on General Recordkeeping Requirements

This section contains a brief summary of major comments and responses on the general recordkeeping requirements contained in the general provisions (40 CFR part 98, subpart A). *See* sections III.C through PP of this preamble for summaries of comments and responses on specific recordkeeping requirements for the individual source categories contained in 40 CFR part 98, subparts C through PP. A large number of comments were received on general recordkeeping requirements covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart A, Content of the Annual Report, the Abbreviated Emission Report, Recordkeeping, and the Monitoring Plan'' and in the individual source category volumes of ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments.''

1. Record Retention

Comment: Several commenters suggested that EPA require retention of records for three years rather than the five years specified in the proposed rule. Some of these commenters stated that three years is consistent with ARP, which is a comparable program that requires electronic reporting of similar, detailed data. Many contended that retaining the large amount of data required by this rule for five years rather than three years is overly burdensome and is not necessary. They indicated that three years of records is sufficient to allow verification of annual GHG reports. A smaller number of commenters supported record retention for five years, which is consistent with permitting and other programs.

Response: In response to public comments, EPA has changed the record retention requirement in the final rule from five years to three years.[19] We agree that a 3-year time period is sufficient to allow for EPA audit and review of records needed to verify the emissions data submitted in annual reports. Changing the record retention duration to three years will reduce the recordkeeping burden for many facilities reporting under this rule. As stated by various commenters, a 3-year record retention requirement would be consistent with the recordkeeping provisions of the ARP and other Federal reporting programs, including the TRI rules and the DOE Energy Information Administration's 1605(b) Voluntary Reporting of GHG Emission and Reductions program.

2. Monitoring Plan

Comment: We received several comments on the QAPP recordkeeping requirement in proposed 40 CFR 98.3(g). Some had questions about the content and level of detail required in the QAPP, and indicated it would be a costly and burdensome requirement. Others stated that the QAPP would be duplicative of their facility SOPs or documentation kept under ARP or other programs. Some commenters indicated that the list of items to report in 40 CFR 98.3(g) was repetitive because a few of the items listed separately would typically be contained in a QAPP.

Response: The final rule requires a ''monitoring plan.'' The ''QAPP'' terminology in the proposed rule caused confusion because ''QAPP'' is used in a variety of other contexts, has various connotations to different readers, and caused readers to presume requirements EPA did not intend. The final rule specifies monitoring plan contents such as:

- Identification of persons responsible for collecting emissions data.
- Explanation of the processes and methods used to collect the necessary data for the GHG emissions calculation.
- Description of the procedures that are used for QA, maintenance, and repair of all CEMS, flow meters, and other instrumentation used to provide data for the GHG emissions reported under 40 CFR part 98.

The first two items in this list were formerly listed as separate line items in the recordkeeping requirements, but would logically be a part of the monitoring plan, so were consolidated under the monitoring plan to avoid repetition.

The monitoring plan paragraph in the final rule explicitly states that the monitoring plan can rely on references to existing corporate documents. Such documents include SOPs, QA programs under Appendix F to 40 CFR part 60 or Appendix B to 40 CFR part 75, and other documents provided that the information required by the monitoring plan is clearly recognizable. The provision allowing the monitoring plan to refer to such documents avoids duplicative effort and addresses the commenters' concerns that monitoring plan information is already contained in other documents.

The final rule also contains a provision to update the monitoring plan. Reporters need their monitoring plan to be up to date in order to ensure that facility or supplier personnel follow the right monitoring and QA procedures and that the reporter meets the requirements of the reporting rule. Likewise, EPA needs to be able to view an up-to-date monitoring plan during facility audits. Updates to the plan would be needed if, for example, the facility makes a process change, changes monitoring instrumentation or QA

[19] As described earlier in this section, facilities or suppliers that have emissions or products with emission less than 25,000 metric tons CO_2e for five years in a row may cease reporting. Those that cease reporting must have records to cover those five years of emissions. Similarly, reporters who demonstrate emissions less than 15,000 metric CO_2e for three years is a row may cease reporting, and must have records to cover those three years of emissions.

procedures, or improves procedures for maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime.

N. Summary of Comments and Responses on Emissions Verification Approach

This section contains a brief summary of major comments and responses on emissions verification of the GHG reports. A large number of comments were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Approach to Verification and Missing Data.''

Comment: Many commenters, including most facilities and suppliers required to report under the rule and several other stakeholders, supported EPA's proposal to require self-certification with EPA verification of GHG reports. These commenters provided a variety of reasons. Many supported EPA emissions verification because the alternative of third party verification would be more costly to reporters. Several also commented that EPA emissions verification would provide a consistent and transparent data set.

Other commenters suggested that EPA require third party verification of GHG reports, and they provided a variety of reasons. A few noted that third party verification is consistent with other GHG reporting systems (e.g., the European Emissions Trading Scheme, The Climate Registry, the California mandatory GHG reporting rule, and other State programs). Many stated that third party emissions verification will improve the quality of the data submittals and told us that third party verification led to the correction of inaccuracies in GHG emission reports submitted under other programs. Some of the commenters questioned whether EPA would have the time to conduct verification, given the number of reports and volume of supporting data that must be submitted. Others were concerned that EPA verification requires submittal of detailed supporting data and contended that some of these supporting data would be CBI.

A smaller number of commenters favored self-certification without independent emissions verification. They believed the designated representative provisions in the rule would cause reporters to take self-certification seriously and ensure the emissions they report are correct. Some also stated that independent verification is not needed for a reporting program that does not require emissions reductions.

Response: In selecting the approach to emissions verification, EPA reviewed all of the comments, as well as emissions verification requirements and procedures under a number of existing EPA regulatory programs and domestic and international GHG reporting programs. Based on this review, EPA considered three alternatives: (1) Self-certification without independent verification, (2) self-certification with third party verification, and (3) self-certification with EPA verification. For this particular program, EPA is not changing the verification approach from the proposal and is requiring self-certification with EPA emissions verification. We decided to retain this verification approach because it provides greater assurance of accuracy and impartiality than self-certification without verification, and has a number of advantages over third party verification for this type of Federal program. Our objective with emissions verification in this program is to ensure collection and dissemination of high-quality data while providing the reporters a ''level playing field'' in terms of requirements and process.

To enable effective review of the large volume of data reported, the rule requires reporters to submit data electronically in a standard format through a centralized data system. EPA is developing this system and intends to make it available to reporters, along with training and instructional materials, before the reporting deadlines. To the extent possible, EPA will leverage existing reporting systems and work with other State and regional programs and systems to develop a reporting scheme that minimizes the burden on reporters.

In implementing the emissions verification under this rule, EPA envisions a two step process. First, we will conduct an initial centralized review of the data which will be largely automated. EPA intends to build into the data system an electronic data QA program for use by reporters and EPA to help assure the completeness and accuracy of data. In addition, to verify reported data and ensure consistency, EPA may review facility-level monitoring plans and procedures, and will perform detailed, automated checks on data utilizing recent and historical data submittals, comparison against like facilities and/or other electronic audit tools where appropriate. Second, EPA intends to follow-up with facilities should potential errors, discrepancies, or questions arise through the review of reported data and conduct on-site audits of selected facilities. The on-site audits may be conducted by private verifiers contracted by EPA or by Federal, State or local personnel, as appropriate. We plan to coordinate closely with the States to develop an efficient approach toward on-site auditing that can meet the needs of multiple programs. We do not anticipate conducting on-site audits of every facility every year.

EPA decided to finalize the rule with EPA emissions verification for several reasons. First, we determined that the combination of comprehensive electronic review and a flexible and adaptive program of on-site auditing will enable us to effectively target verification resources while also providing the necessary consistency and quality in the data. Utilizing the national data set developed under this rule will provide unique resources for the review of reports. A centralized emissions verification system provides greater ability for EPA to identify trends and outliers in data and thus assist with targeted follow-up review, and our approach can evolve over time as we gain experience with GHG reporting. This approach also provides opportunity to work closely with and leverage both the experience and ongoing activities of States and others already engaged in similar and different types of GHG reporting.

Our emissions verification approach in this rule is consistent with other EPA emission reporting programs and follows a model similar to the ARP which is a highly successful emissions cap and trade program that consistently produces credible, high-quality data. Facilities regulated under ARP must have a Designated Representative sign data reports to self-certify that the reported data are accurate. Then, facilities and EPA use a series of electronic tools to ensure proper data collection and reporting, including establishing a monitoring plan, calibrating equipment to certain specifications, frequent testing and data submittal. Similar to what we are intending with this program, EPA conducts site audits on those facilities targeted during the electronic review as having been outliers or had anomalies in their reported data. These audits are done by EPA personnel, States and/or contractors to EPA. We support these audits by providing a field audit manual to both government and private auditors as well as additional training to State and Federal auditors.

Second, this approach is the best way to address the many comments we received on the importance of obtaining 2010 data and making the data widely available. EPA has determined that this verification approach will enable us to make data available more quickly than under a third party verification approach. We will be able to share a complete data set promptly upon completion of the electronic review (subject to relevant CBI concerns, please see the discussion of our plans to address CBI and emissions data in Section II.S of this preamble and ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues''). We determined that the third party verification approach could take from three to six months after initial data submission, and EPA would still need to review and perform consistency checks after the third party verification was complete.

In addition, developing the third party verification approach would require EPA to establish and develop emissions verification protocols and a system to qualify and accredit the third party verifiers, and to develop and administer a process to ensure that verifiers hired by reporting facilities do not have conflicts of interest. Such a program could require EPA to review numerous individual conflict of interest screening determinations made each time a reporter hires a third party verifier. Even if EPA were to partner with an existing program or organization to accredit verifiers, EPA would still need to develop the criteria and systems described above to implement this rule and ensure high quality emissions verification given the unique reporting requirements of this rule. These efforts would slow down implementation of the rule and sharing of data.

Finally, we agree with many of the commenters regarding their concerns about the cost of third party verification. Given the information currently available to us, under a third party verification approach we would have required that each facility verify its submission each year. As a national reporting program with a substantially larger number of reporters than existing State programs, we determined that the costs to the reporters of third party verification would have been substantial. By finalizing self-certification with EPA emissions verification for this rule, it also ensures a lower cost burden for reporters.

EPA's decision to use self certification with EPA emissions verification was made in the context of the specific scope of this rulemaking, the types of data to be collected, and the intended uses of the emissions data. For other types of programs (e.g., offsets, corporate footprinting, energy efficiency) other verification approaches may be more suitable. We recognize that many GHG reporting and reduction programs developed by the States and Regions are broader in scope and for this and other reasons, the use of third party verifiers is an appropriate way to verify the data they collect. EPA's decision in this rulemaking does not preempt State GHG reporting programs or any other programs from requiring third party verification. More importantly, the selection of EPA emissions verification for this rule is not intended to suggest that third party verification cannot result in accurate, high quality data.

EPA received a smaller number of comments in support of self-certification without emissions verification. While recognizing that this approach would place a low burden on both reporters and the government, it also has major disadvantages. Without any verification of submitted reports, there is far greater potential for inconsistent and inaccurate data and this will result in less confidence at EPA and with public stakeholders in the data. These disadvantages would make the data collected under this option less useful for informing decisions on climate policy and supporting the development of potential future policies and regulations.

Comment: Commenters asked what role State and local regulatory agencies will have in verification of reported emissions data. Some suggested that State and local agencies should assist with emissions verification because they already have detailed knowledge of the facilities in their areas. Some indicated that States would need resources to play a role in verification and other rule implementation activities.

Response: While EPA is responsible for emissions verification as explained in the previous response, EPA will likely enlist State assistance, when it is available, during the implementation phase of the final rule. (However, State and local agencies will not be required to provide EPA any assistance with verification or implementation activities, given State and local agency resource constraints and priorities.) For example, in concert with their routine inspection and other compliance and enforcement activities for other CAA programs, State and local agencies could, as resources allow, assist with educating facilities and assuring compliance at facilities subject to this rule.

Assistance from State and local agencies could include such activities as identifying the facilities for on-site audits or conducting audits where appropriate. This type of assistance from State and local governments has been valuable in other programs. State and local air pollution control agencies routinely interact as part of other regulatory programs with many of the sources that would report under this rule. States have knowledge of specific facilities and sources that would be required to report under this rule. In addition, many States have already implemented or are in the process of implementing GHG reporting and reduction programs. Therefore, some State and local agencies could serve a role in communicating the requirements of the rule and providing compliance assistance.

O. Summary of Comments and Responses on the Role of States and Relationship of This Rule to Other Programs

This section contains a brief summary of major comments and responses. A large number of comments on the relationship between this rule and other programs were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Relationship to Other GHG Reporting Programs'' and ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues.''

Comment: Several commenters requested that EPA make it clear that States can collect additional GHG data under State rules and GHG programs and are not limited to collecting only the data in this Federal mandatory reporting rule. Other commenters requested that this rule preempt or supersede State GHG reporting rules.

Response: EPA reaffirms that States can collect additional data under State rules and GHG programs, and that this rule does not preempt or replace State reporting programs. This rule has been developed in response to a specific request from Congress (in the Appropriations Act) and is narrower and more targeted than many existing State programs that are coupled with GHG emission reduction programs. As EPA stated in Section II of the proposal preamble (74 FR 16457, April 10, 2009) and Section I.E of this preamble, many State programs are broader in scope, in a more advanced state of development, and have different policy objectives than this rulemaking. These are important programs that not only led the way in reporting of GHG emissions before the Federal government acted but also have catalyzed important GHG reductions.

EPA supports and recognizes the success and necessity of State programs as a vital component in achieving GHG emissions reductions, particularly those focused on energy efficiency improvements. It is appropriate that State and regional GHG reporting and reduction programs have different scopes or implementation schedules, and that they require reporting of different information than this rule for various program-specific reasons. For example, some State programs might require reporting of electricity purchases and other data to provide information for energy efficiency programs; they may require or allow reporting of a variety of indirect emissions to gather data to help facilities reduce their carbon footprint; they may require or allow reporting of emissions such as from fleet vehicles to encourage fleet operators to take steps to reduce emissions; or they may be developing or implementing GHG reduction rules including cap and trade programs, and require specific information on emissions and offsets to implement those programs. State programs already have, or may evolve to include, additional monitoring and reporting requirements than those included in this rule. Many States are actively collecting additional data they need for their programs and policies, and this reporting rule does not preempt State programs.

Comment: Some commenters were concerned that the Federal GHG reporting rule will result in duplicative reporting for facilities that are also reporting GHG emissions under State rules or voluntary GHG reporting programs. Some requested that to reduce burden, facilities should be required to submit data only once, and not have to submit different data to multiple different programs. Some commenters strongly recommended that the electronic data systems used by this reporting rule and other programs need to be consistent and allow data exchange between this rule and TCR, State rules, National Emissions Inventory (NEI), ARP, or other programs. Many commenters supported submittal of all data directly to EPA, while others favored delegation of data collection to State agencies to encourage consistency between State and Federal data collection efforts.

Response: EPA carefully considered the issue of State delegation, particularly in light of the leadership and experience of several States in developing GHG reporting and reduction programs, and also in the context of the pressing need for a national reporting program and the strong emphasis placed by the vast majority of the commenters on this rule for EPA to ensure that data collection begins on January 1, 2010 and that data are reported early in 2011. We determined that developing a program to delegate to States would take additional time and would not be available for 2010 reporting, and we also determined that a significant number of States would likely not request delegation, which would increase the complexity of assembling a consistent national data set. For these reasons, we determined that the most effective way to achieve nationwide GHG reporting of 2010 data was for reporters to submit data directly to EPA, as proposed. Additional reasons for selection of this data flow approach are described in the response on emissions verification in Section II.N of this preamble, the responses on collection, management, and dissemination of GHG emissions data in Section V of this preamble, and the responses on compliance and enforcement in Section VI of this preamble.

While EPA is not formally delegating rule implementation and enforcement to States, we are committed to working in partnership to address the issues expressed in their comments on interaction between State and Federal reporting programs. Design and implementation of electronic systems for data systems has been an area of particular focus in determining how to ease reporting burdens and facilitate use of the many different types of data collected by State and Federal reporting programs by all levels of government.

EPA is committed to working with States to develop electronic reporting tools that can both collect and share data in an efficient and timely manner. At this time, EPA is in the process of developing the reporting format and tools and therefore has not specified the exact reporting format, other than it will be electronic, in order to maintain flexibility to modify the reporting format and tools in a timely manner. To the extent possible, EPA will work with existing reporting programs and systems to develop a reporting scheme that minimizes the burden on sources.

EPA recognizes the need to develop reporting tools that can support reporting across programs that collect different types of data, and we intend to coordinate with States and other organizations to explore development of shared web-based tools that can simplify and expedite reporting. We recognize that State and regional programs may be collecting additional GHG information beyond what is required in this rule. For example, many of these programs collect emissions data on fleet vehicles, indirect emissions data for utility purchase, and other data not required by the Federal rule. Moreover, our rule requires reporting of additional data necessary for emissions verification, which is likely more expansive than what many existing State and regional programs are collecting. For example this rule requires reporting of emissions at the process or unit level for many source categories, rather than the company or facility level as allowed by various other mandatory and voluntary reporting programs. We will also collect detailed monitoring data and activity data used to calculate emissions, which will enable emissions verification. We are interested in working with others to determine the extent to which shared tools can be designed to facilitate reporting across multiple programs, consistent with obligations regarding CBI.

EPA carefully reviewed Federal, State, and international voluntary and mandatory programs during development of the reporting rule and attempted to be consistent with the GHG protocols and requirements within these rules, to the extent feasible given the differing scopes and policy objectives. (*See* Section II of the preamble for the proposed rule (74 FR 16457, April 10, 2009), the Review of Existing Programs memorandum (EPA–HQ–OAR–2008–0508–052), and the memorandum summarizing State mandatory rules (EPA–HQ–OAR–2008–0508–054).) EPA has worked with and will continue to coordinate closely with other Federal, State, and regional programs to facilitate data exchange when designing the data reporting systems that will be used for the rule and planning implementation activities. We will work with the States, TCR, and others on data exchange standards to ease sharing of data between systems, consistent with CBI obligations. And finally, we see substantial opportunities for EPA and States to cooperate on strategic efforts to identify uses of the data collected under this rule and work together on a broad array of climate change issues.

P. Summary of Comments and Responses on Other General Rule Requirements

This section contains a brief summary of major comments and responses on other general rule requirements. A large number of other general comments were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's

Response to Public Comments'' volumes on subpart A.

1. Research and Development

Comment: Commenters representing institutions and industries subject to the reporting rule requested an exclusion for R&D activities. They noted that the aluminum production and glass production subparts of the proposed rule excluded R&D process units, but requested that R&D be excluded from the rule as a whole, not only from the two subparts. Some also commented that the exclusion should encompass R&D activities other than R&D process units, including bench scale laboratory research and pilot plants. Commenters pointed out that many other EPA air rules exclude R&D and they explained that R&D activities are small-scale, emissions change frequently as the focus and scope of the R&D activity changes, reliable information on CO_2e emissions during any particular phase of the research might not be available, and quantifying R&D emissions would impose a high burden relative to the quantity of emissions.

Response: In response to these public comments, EPA has added an R&D exclusion in 40 CFR 98.2(a)(5) stating that R&D activities are not considered to be part of any source category defined in 40 CFR part 98. Because R&D activities are not included in any source category, their GHG emissions are not reported. EPA agreed with the commenters that R&D process units and laboratory R&D for new processes, technologies, or products should be excluded. It is not reasonable to calculate GHG emissions from processes and activities that continually change as the research focus changes and have highly variable inputs and operating conditions due to their R&D nature. Also, emissions from R&D are expected to be small. Therefore, the final rule defines R&D as activities conducted in process units or at laboratory bench scale settings whose purpose is to conduct R&D for new processes, technologies, or products, and whose purpose is not for the manufacture of products for commercial sale, except in a *de minimis* manner.

We point out that the exclusion applies to each individual R&D activity that meets the R&D definition, not to an entire facility as a whole. For example, a facility that has some commercial process units and some R&D process units can exclude only the R&D process units. A facility that meets the applicability criteria in 40 CFR part 98, subpart A and contains general stationary combustion sources must report emissions from the combustion units, even if the steam, heat, or electricity generated by a combustion unit is used in an R&D process unit. Laboratory activities are excluded only if they are for R&D purposes. Laboratory analyses activities conducted for commercial purposes, process operating purposes, or to comply with a rule would not be excluded.

We decided not to include pilot plants in the definition of R&D. Pilot plants that meet the rule applicability criteria must report their GHG emissions. Pilot plants tend to be relatively large in scale compared to the excluded R&D activities. Because pilot plants are designed to prove the viability of a particular process or technology rather than to research a wide range of processes and products, their operations and emissions are more consistent than the excluded R&D activities. Pilot plants also tend to be operated for relatively long periods of time and in some cases are converted to commercial facilities. For these reasons, EPA views the data as more useful and has not applied the R&D exclusion to pilot plants.

2. Determining Applicability

Comment: Some commenters were concerned that the GHG reporting rule will virtually require every commercial and industrial facility to collect fuel usage data and perform relatively complex calculations, and in some cases modeling, in strict accordance with the prescribed monitoring methodologies and emissions calculation procedures, to determine if they are subject to the rule. The commenters added that this will be burdensome, especially for small sources that will just be documenting that the calculated GHG emissions from the facility are well below the reporting threshold. They also indicated that recordkeeping would be needed to show that facilities are below the reporting threshold, and anticipated that the rule will be nearly as burdensome on facilities that do not have to report, as on those that must report. Many of the commenters asked that EPA provide simplified source category thresholds to determine applicability, like the 30 mmBtu/hr aggregate maximum rated heat input capacity for stationary fuel combustion units, to reduce the burden on the majority of facilities making applicability determinations.

Response: We disagree that the initial applicability determination process is burdensome. While the rule requires reporters who are subject to the rule to determine applicability using the calculation procedures required in the rule, the rule does not contain any requirements for facilities that are not subject to the rule. Therefore, the rule does not necessarily require monitoring in 2010 to determine applicability. To determine applicability, anyone who believes their facility might be subject to the rule could start by calculating emissions using the relevant equations provided in each applicable subpart along with the available data from company records and the likely operating scenario for the reporting year that would lead to worst case GHG emissions. For example, for the input parameters needed for the equations, use the 2010 production goals from the company's business plan, company records, process knowledge, engineering judgment, and vendor data (e.g., vendor information could be used to estimate the carbon content of feedstocks, using the highest likely carbon content of those feedstocks.) EPA expects that for most facilities, emissions calculated in this manner are likely to be significantly above or below the 25,000 metric ton CO_2e per year threshold, such that most potential reporters can determine their applicability to the rule solely using the available data.

For those facilities with estimated emissions that are near the 25,000 tons/year threshold using available data, the company will have to make the decision on whether to install monitoring equipment to calculate emissions during the 2010 reporting year for purposes of determining applicability and/or reporting emissions. It is in a facility's interest to collect the GHG data required by the rule if they think they will meet or exceed the applicability criteria in 40 CFR 98.2 by the end of the year. EPA anticipates that relatively few potential reporters will face uncertainty in making this decision.

Given the large number of industrial and commercial facilities potentially subject to the rule due to stationary fuel combustion emissions, EPA has provided in 40 CFR 98.2 simplified procedures for calculating emissions from fuel combustion. These facilities may first assess applicability based on the aggregate heat input capacity of all their fuel combustion units. Per 40 CFR 98.2(a)(3), facilities with an aggregate maximum rated heat input capacity of less than 30 mmBtu/hour are automatically not covered under the rule, because emissions of CO_2e will be less than 25,000 metric tons of CO_2e per year in all cases. If a facility is not below the 30 mmBTU/hour cutoff, the next logical step to determine applicability is to use any of the four calculation methods provided in subpart C, as allowed by 40 CFR 98.2(b). The simplest of the four methods requires determination of only one parameter—

annual fuel use. Most companies already record fuel use, and can use this to calculate emissions and determine applicability.

To assist facilities in determining applicability, EPA plans to provide implementation guidance with simplified means to determine applicability. For combustion sources, EPA plans to publish tables that will specify by fuel type both an annual fuel consumption level and maximum heat input capacity that correlates with emissions of 25,000 metric tons per year of CO_2e. For non-combustion source categories with a 25,000 metric ton CO_2e threshold, EPA plans to publish guidance, as feasible, on equipment capacities, production levels, or other parameters that correlate with emissions of 25,000 metric tons per year of CO_2e. The capacity and production levels provided in these tables would be based on worst-case assumptions, but would allow facilities to quickly and easily determine if they need to develop more precise estimates or plan to implement monitoring in 2010.

Q. Summary of Comments and Responses on Statutory Authority

This section contains a brief summary of some major comments and responses. A large number of comments on statutory authority were received covering numerous topics. This section will highlight only two of the key categories of comments. Additional discussion on these comments and others can be found in the comment response documents.

Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues''.

Comment: EPA received numerous comments on whether the CAA or the FY 2008 Consolidated Appropriations Act authorized the rule. Some commenters argued that EPA was required to issue the reporting rule under the authority created by the Appropriations Act, not the CAA. Others argued that the Appropriation Act could not create new authority, and therefore either (1) EPA had to rely on the CAA, or (2) EPA was not authorized to issue the rule at all.

Response: As noted above, EPA is relying on the authority provided in the CAA, not the Appropriations Act, for this final rule. While the Appropriations Act required that EPA spend a certain amount of money on a rule requiring mandatory reporting of GHG emissions, the authority to gather such information already existed in the CAA. Indeed, EPA could have promulgated this rule in the absence of the Appropriations Act. Thus, the comments about the inability of an appropriations law to create new legal authority are inapposite to this rulemaking.

Comment: Commenters opined on whether the statute in question (either the Appropriations Act or the CAA) contained sufficient authority for various elements of the rule, ranging from broad issues like the scope and duration of the rule as a whole, to more specific issues related to particular source categories covered, and specific monitoring, recordkeeping and reporting requirements.

Several commenters argued that the appropriations language contained limitations on the scope of the rule EPA could promulgate, regardless of the underlying authority for the rule. For example, some commenters contended that because the appropriations were for a single fiscal year, EPA was authorized to promulgate only a one-time data collection. Others argued that the Appropriations Act authorized the collection solely of GHG emissions, and not any of the additional data elements related to verification of emissions data.

As for the CAA, some commenters questioned whether section 114 authorized a broad reporting rule, as opposed to the targeted 114 information requests used by EPA in the past. Many commenters questioned whether EPA had adequately linked the requirements of the reporting rule to particular provisions of the CAA that EPA was carrying out. Others questioned EPA's general ability to gather information about GHGs before it had made an endangerment finding and/or regulated GHGs under the CAA.

Not all comments were negative. Some commenters supported EPA's interpretation of the CAA, and agreed that it authorized the proposed reporting rule.

Response: We disagree that the language in the Appropriations Act limited EPA's authority for this rule. First, the Environmental Programs and Management (EP&M) funds Congress appropriated for the GHG reporting rule are available for two fiscal years as are the funds EPA historically has used for most other Agency rules. The fact that the appropriations EPA uses to develop rules are available for specified fiscal years does not mean that the effectiveness of the rules is limited by the same period of time that the funds are available. Moreover, as noted above, EPA is issuing this rule under the authority of the CAA, and indeed EPA could have issued this rule absent the direct instruction from Congress to spend at least a certain amount of money on a mandatory GHG reporting rule. Thus, we do not agree that the appropriations language limited EPA's ability to collect the information under this rule, either in duration or scope of the information requested.

Regarding the scope of the rule, while it is true that EPA has used section 114 in a more targeted fashion in the past, there is nothing in the CAA that so limits our ability. EPA is undertaking a comprehensive evaluation of GHGs under the CAA and hence, is issuing a comprehensive reporting rule.

Moreover, as noted above, CAA sections 114 and 208 authorize EPA to gather the information under this rule, which will prove useful to EPA in carrying out numerous provisions of the CAA. This final rule imposes requirements on direct sources of GHG emissions. These sources are clearly persons from whom the Administrator may gather information under CAA section 114, as long as that information is for purposes of carrying out any provision of the CAA. As discussed further in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Selection of Source Categories to Report and Level of Reporting'' and ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues,'' the information provided by direct emitters will prove invaluable to the Agency in several areas, including the evaluation of the appropriate action to take under section 111 regarding NSPS, and the investigation into non-regulatory strategies to encourage pollution prevention pursuant to section 103(g). For example, the Agency currently has pending before it a court remand, comments in an ongoing rulemaking, a petition for reconsideration, notices of intent to sue and litigation regarding EPA's treatment of GHGs under section 111.

The requirements applicable to manufacturers of mobile sources are authorized by section 208 because they will help inform various options regarding the regulation of these sources under title II of the CAA. The Agency currently has pending before it several petitions requesting that the Agency regulate emissions from a variety of mobile sources, including motor vehicles, aircraft, nonroad engines and marine engines.

Finally, the final rule also gathers information from upstream suppliers of industrial GHGs and fossil fuels (except for suppliers of coal). The information gathered from suppliers of fossil fuels, in particular petroleum products, is relevant to an evaluation of possible regulation of fuels under title II of the

CAA, as well as for potential efforts to address GHG emissions at downstream sources. Information from suppliers of industrial GHGs is relevant to understanding the quantities and types of gases being supplied to the economy, in particular those that could be emitted downstream which will aid in evaluating action under CAA section 111 as well as various sections of title VI (e.g., 609 and 612) that address substitutes to ozone depleting substances (ODS). Additional discussion on this issue is available in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Selection of Source Categories to Report and Level of Reporting'' and in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues.''

Finally, we disagree with commenters who argue that we cannot use CAA sections 114 of 208 to gather information on a pollutant until we have issued an endangerment finding for that pollutant, or actually decided to regulate it under the CAA. The statute is not so inflexible. [20] For example, the information collected under sections 114 and 208 could inform the contribution element of endangerment determinations (e.g., whether emissions from the relevant sector contribute to air pollution which may reasonably be anticipated to endanger public health or welfare). Similarly, information gathered under these sections could inform decisions on whether to regulate a pollutant or source category. Commenters' interpretation would prevent EPA from gathering information that could be critical to key decisions until after those decisions are made. EPA does not agree with, and will not adopt, such an interpretation.

Thus, as discussed in more detail above and in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues,'' EPA has adequate authority to issue this rule.

R. Summary of Comments and Responses on CBI

This section contains a brief summary of major comments and responses on CBI issues. A large number of comments were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues.''

Comment: EPA received numerous comments addressing the issue of CBI. Industry commenters generally expressed concern that much of the information reported under this rule would be CBI (e.g., production and process data). Many commenters also presented arguments regarding why certain information would not be ''emissions data'' under the CAA. Among the various recommendations were that the final rule (i) not require the reporting of such information at all, (ii) require only that the source maintain such information on site, but not report it to EPA, and/or (iii) clearly state that some classes of information are CBI. Some commenters expressed concern about EPA's ability to maintain the confidentiality of CBI, and thus suggested that EPA should provide further detail regarding how we will protect CBI from disclosure. The agricultural industry expressed particular concerns about making information about the location of facilities public due to concerns about biosecurity and other potential threats. Other commenters favored the wide dissemination of information, and argued that the information gathered under this rule should be ''emissions data'' and hence not protected as CBI.

Response: As discussed in Section II.N of this preamble, EPA is finalizing its proposal that EPA verify the information collected by this rule. Data regarding inputs into emissions calculations and monitoring are critical elements of that verification process. Because EPA will routinely need this data in order to verify the information collected under this rule, we are not adopting the recommendation that sources maintain such information on site and only provide it during an inspection or when otherwise specifically requested.

EPA also recognizes the importance of this issue to both reporters and the public. EPA's public information regulations contain a definition of ''emissions data'' at 40 CFR 2.301, and EPA has discussed in an earlier **Federal Register** notice what data elements constitute emissions data that cannot be withheld as CBI (56 FR 7042–7043, February 21, 1991). We further recognize that while determinations about whether information claimed as CBI meets the definition of CBI, as well as whether it meets the definition of emissions data, are usually made on a case-by-case basis, such an approach would be cumbersome given the scope of this rule and the potential inconsistencies across reporters and source categories and the compelling need to make data that are not CBI, or are emissions data, available to the public. For this reasons, EPA intends to undertake an effort similar to what was done in 1991 for the data elements collected in this rule. Through a notice and comment process, we will establish those data elements that are ''emissions data'' and therefore will not be afforded the protections of CBI. As part of that exercise, in response to requests provided in comments, we may identify classes of information that are not emissions data, and are CBI. EPA plans to initiate this effort later this year, or in early 2010. We will consider the comments received on this issue as part of that notice and comment process.

As stated in the proposed rule, EPA will protect any information claimed as CBI in accordance with regulations in 40 CFR part 2, subpart B. As we noted previously however, in general the CAA prohibits the treatment of emission data collected under CAA sections 114 and 208 as CBI.

S. Summary of Comments and Responses on Other Legal Issues

This section contains a brief summary of major comments and responses on other legal issues. A large number of other legal issue comments were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues.''

Comment: We received numerous comments on EPA's statements in the proposed rule that a final rule requiring the monitoring and reporting of GHG emissions would not render GHGs ''regulated pollutants'' under the CAA. See, e.g., ''EPA's Interpretation of Regulations that Determine Pollutants Covered By Federal Prevention of Significant Deterioration (PSD) Permit Program'' (Dec. 18, 2008) (''PSD Interpretive Memo). Some agreed, while others took issue with the position in the memorandum.

Response: As we noted in the proposal, EPA is reconsidering the PSD Interpretive Memo and will be seeking public comment on the issues raised in it. That proceeding, not this rulemaking, is the appropriate venue for submitting comments on the substantive issue of whether monitoring regulations under the CAA should make GHGs subject to regulation. At this time however, the PSD Interpretive Memo reflects EPA's current position, and hence, this final rule does not make GHGs subject to regulation under the CAA.

Comment: EPA also received numerous comments about whether the requirements imposed by this rule are

[20] We note that the statute is ambiguous, and thus EPA may adopt any reasonable interpretation. *See Chevron* v. *NRDC et al.,* 467 U.S. 837, 864 (1984).

''applicable requirements'' under the title V operating permit program. The majority of the comments took the position that the current definitions of ''applicable requirement'' at 40 CFR 70.2 and 71.2 do not include a rule such as this, promulgated under CAA section 114(a)(1) and 208. Commenters requested that EPA confirm their interpretation of the regulations.

Response: As currently written, the definition of ''applicable requirement'' in 40 CFR 70.2 and 71.2 does not include a monitoring rule such as today's action, which is promulgated under CAA sections 114(a)(1) and 208.

III. Reporting and Recordkeeping Requirements for Specific Source Categories

A. Overview

Once a reporter has determined that its facility or supply operation meets any of the reporting rule applicability criteria in 40 CFR 98.2(a), the reporter must calculate and report GHG emissions or alternate information as required (e.g., suppliers report quantities supplied and the quantity of CO_2e that could be emitted when the products they supply are combusted or used). The applicability threshold determination is separately assessed for suppliers (fossil fuel suppliers and industrial GHG suppliers) and downstream source categories (facilities with direct GHG emissions).

The required GHG information must be reported for all source categories at the facility for which there are measurement methods provided. For suppliers (facilities or corporations) that trigger only the applicability criteria for upstream fossil fuel or industrial GHG supply (40 CFR part 98, subparts KK through PP), reporters need only follow the methods and report the information specified in those respective subparts. For downstream facilities that contain exclusively direct emitting source categories covered in 40 CFR part 98, subparts C through JJ, and are not suppliers, reporters must monitor and report GHG emissions the methods presented in each applicable subpart. Some reporters will need to report under multiple subparts because multiple source categories are collocated at their facility. For example, a facility with petrochemical production processes (described in Section III.X of the preamble), should also review Sections III.C (general stationary fuel combustion), III.G (ammonia manufacturing) and III.Y (petroleum refineries) of this preamble. In some cases, such as petroleum refineries that supply petroleum products and also meet applicability criteria for direct emissions from the refinery, reporters will have to report on both supply operations and direct facility emissions.

Table 2 of this preamble (in the **SUPPLEMENTARY INFORMATION** section of this preamble) provides a cross walk to aid facilities and suppliers in identifying potentially relevant source categories. The cross-walk table should only be seen as a guide as to the types of source categories that may be present in any given facility and therefore the methodological guidance in Section III of this preamble that should be reviewed. Additional source categories (beyond those listed in Table 2 of this preamble) may be relevant to a given reporter. Similarly, not all listed source categories will be relevant to all reporters.

Consistent with the requirements in the 40 CFR part 98, subpart A, reporters must report GHG emissions from all source categories located at their facility including stationary combustion 40 CFR part 98, subpart C) and process emissions (e.g., from adipic acid production, iron and steel production, and other source categories in 40 CFR subparts C through JJ), as well as the required data for any supplier source categories (KK through PP). The methods presented typically account for normal operating conditions, as well as startup, shutdown, or malfunction (SSM), where significant (e.g., HCFC–22 production and oil and gas systems). Although SSM is not specifically addressed for many source categories, emissions calculation methodologies relying on CEMS or mass balance approaches would capture these different operating conditions.

For many facilities, calculating facility-wide emissions will simply involve adding GHG emissions from combustion sources calculated under Section III.C of this preamble (General Stationary Fuel Combustion Sources) and process GHG emissions calculated under the applicable the source category subpart(s). The rule also clarifies reporting for more complex situations, such as where combustion and process emissions are comingled. See Section II.L of this preamble for a response to comments on the general monitoring and reporting approach for facilities with both combustion and process emissions. *See* sections III.C through PP of this preamble for discussion of the specific monitoring and reporting requirements for each source category.

B. Electricity Purchases

1. Summary of the Final Rule

The final rule does not require facilities to report their electricity purchases or indirect emissions from electricity consumption.

2. Summary of Major Changes Since Proposal

There have been no changes since proposal. The proposed rule did not require reporting of electricity purchases and neither does the final rule.

3. Summary of Comments and Responses

The proposal preamble (74 FR 16479, April 10, 2009) requested comments on the value of collecting information on electricity purchases under this rule. It also outlined three options for reporting and requested comments on these options:

- *Option 1:* Do not require any reporting on electricity purchases or associated indirect emissions from purchased electricity as part of this rule.
- *Option 2:* Require reporting of purchased electricity from all facilities that are already required to report their GHG emissions under this rule.
- *Option 3:* Require reporting of indirect emissions from purchased electricity for facilities that exceed a prescribed total facility emission threshold (including indirect emissions from the purchased electricity). Reporting under this option could be either in terms of electricity purchases or calculated CO_2e emission based on purchased electricity.

While EPA is not including reporting requirements for electricity purchases in the final rule at this time, below we have provided a brief summary of major comments and our initial responses. As EPA considers next steps, we will be reviewing the public comments and other relevant information.

In Favor of Collecting Data on Electricity Purchases

Comment: Commenters in favor of collecting data on purchased electricity stated that collection of this data, in conjunction with data on direct emissions from facilities, will present a more comprehensive picture of emissions nationwide. They argued that collection of this data will also serve to spur investment in energy efficiency and renewable energy since companies will want to improve their emissions numbers once the information is made public. Several commenters noted that while this reporting should occur, it should happen at the corporate level, rather than at the facility level. Others stated that the collection should begin at a later time, perhaps in a second phase of this rule.

Response: While EPA is not collecting data on electricity purchases in this rule, we understand that acquiring such data may be important in the future. Therefore, we are exploring options for possible future data collection on electricity purchases and indirect emissions, and the uses of such data. Such a future data collection on indirect emissions would complement EPA's interest in spurring investment in energy efficiency and renewable energy. Energy efficiency is a low cost, vital first step toward reducing GHG emissions. To this end, EPA has in place several programs in which corporations and individual facilities can participate to reduce their contribution to GHG emissions through increased energy efficiency of buildings and industry. These include EPA's ENERGY STAR and Climate Leaders programs.

EPA has been working for more than a decade through the ENERGY STAR program to help companies reduce their energy use through cost-effective energy efficiency investments and practices. ENERGY STAR provides nonresidential building owners and operators and energy intensive industries with a wide variety of tools and resources to assist in their efforts to reduce building energy use. These include an online energy benchmarking and tracking tool called Portfolio Manager, Guidelines for Energy Management, technical resources to assist in assessing building upgrades, and many others.

Through the Climate Leaders Program, EPA works corporate-wide with companies to develop comprehensive climate change strategies. Partner companies commit to reducing their impact on the global environment by completing a corporate-wide inventory of their GHG emissions based on a quality management system, setting aggressive reduction goals to be achieved over 5 to 10 years, and annually reporting their progress to EPA. Through program participation, companies create a credible record or audit of their accomplishments and receive EPA recognition as corporate environmental leaders.

In addition to these programs that support GHG emissions reductions in both the private and public sectors, EPA's Climate and Energy State and Local Program assists governments in their clean energy efforts by providing technical assistance, analytical tools, and outreach support. While EPA assists States in this way, we also have much to learn from their efforts. Throughout the country, States are engaged in activities on energy efficiency, energy auditing, and some collect data on electricity purchases for use in inventories and in energy efficiency programming.

Since the goal of today's rule is to collect data on emissions from downstream direct emitters and upstream production, the collection of indirect emissions will not be included at this time. In exploring the possibility of collecting data on electricity purchases nationwide, EPA will be looking to the States as examples. While facility level collection is a possibility, collection from other sources, such as load serving entities will also be explored. Moreover, the collection of indirect emissions data from the types of facilities covered by this rule (e.g., facilities and suppliers with emissions over 25,000 metric tons of CO_2e) would not provide the complete picture or focus on the types of facilities that likely have large indirect emissions. Reports from additional facilities could be required in any future data collection.

Against Collecting Data on Electricity Purchases

Comment: Many commenters were against the collection of data on purchased electricity for several reasons. Primarily they felt it would constitute double counting if electricity data are collected from electric utilities and EPA also collects the same data from facilities and adds it together. Others stated that collecting information on electricity purchases was outside the scope of the rule, that it is not useful information in attempting to quantify emissions, that it would be burdensome for facilities, and that it is CBI that companies are not able to share with EPA. Those commenters suggested instead the data should come from utilities, as EPA proposed.

Response: The final rule does not require facilities to report their electricity purchases or indirect emissions from electricity consumption. While EPA is not collecting data on electricity purchases in this rule, we understand that acquiring such data may be important in the future. Therefore, we are exploring options for possible future data collection on electricity purchases and indirect emissions, and the uses of such data. In the event that a future data collection effort is pursued, EPA will consider the issues raised by these commenters with regard to the most effective source for this data, and methods to reduce burden on reporting entities.

With regard to, double reporting and/or double counting of the same data, the data collected under this rule is consistent with the appropriations language, and provides valuable information to EPA and stakeholders in the development of climate change policy and programs. Policies such as low carbon fuel standards can only be applied upstream, whereas end use emission standards can only be applied downstream. Data from upstream and downstream sources would be necessary to formulate and assess the impacts of such potential policies. Eliminating reporting by either upstream or downstream sources would not satisfy EPA's data needs and policy objectives of this rule. Any future rule makings to collect data on electricity purchases and indirect emissions will follow a similar approach in order to inform policy decisions.

With regard to CBI, EPA recognizes the importance of this issue to both reporters and the public. EPA's public information regulations contain a definition of ''emissions data'' at 40 CFR 2.301, and EPA has discussed in an earlier **Federal Register** notice what data elements constitute emissions data that cannot be considered CBI (56 FR 7042–7043, February 21, 1991).

As explained in Section II.R. of this preamble, EPA intends to undertake a similar effort regarding the data elements collected in this rule, and any subsequent rules. Through a notice and comment process, we will establish those data elements that are ''emissions data'' and therefore will not be afforded the protections of CBI.

C. General Stationary Fuel Combustion Sources

1. Summary of the Final Rule

Source Category Definition. Stationary fuel combustion sources are devices that combust any solid, liquid, or gaseous fuel to:

• Produce electricity, steam, useful heat, or energy for industrial, commercial, or institutional use; or

• Reduce the volume of waste by removing combustible matter.

These devices include, but are not limited to, boilers, combustion turbines, engines, incinerators, and process heaters.

Portable equipment, emergency generators, and emergency equipment are excluded from this source category. Stationary combustion devices that combust hazardous waste must report emissions only from the co-firing of any fuels that are covered by 40 CFR part 98, subpart C. Flares are also excluded from subpart 40 CFR part 98, subpart C. Flare emissions must be reported only if required by the provisions of another subpart of part 98.

Reporters must submit annual GHG reports for stationary fuel combustion units if the facility meets the applicability criteria in the General Provisions (40 CFR 98.2) as summarized in Section II.A of this preamble.

EGUs that are subject to the ARP and other EGUs that are required to monitor and report to EPA CO_2 mass emissions year-round according to 40 CFR part 75, are covered under 40 CFR part 98, subpart D (Electricity Generation).

GHGs to Report. For stationary fuel combustion, report:

• CO_2, CH_4, and N_2O emissions from each stationary fuel combustion unit. For each unit, CO_2, CH_4, and N_2O emissions must be reported for each fuel combusted (including biomass). Reporters can aggregate emissions from multiple units in certain cases.

• Facility-level CO_2 emissions from combustion of biomass (in addition to unit-level reporting).

GHG Emissions Calculation and Monitoring. Reporters must use the following methodologies to calculate emissions:

• *Calculating* CO_2 Emissions from Combustion: Calculate CO_2 emissions using one of four methodological tiers, subject to certain restrictions based on unit size, type of fuel burned, and other factors. For each Tier, CO_2 mass emissions are determined as follows:

—*Tier 1:* Use annual fuel consumption (from company records) together with fuel-specific default high heat values and default CO_2 emission factors.

—*Tier 2:* Use annual fuel consumption (from company records) together with measured fuel-specific high heat values and default CO_2 emission factors.

—*Tier 3:* Use annual fuel consumption, either from company records (for solid fuels) or directly measured with fuel flow meters (for liquid and gaseous fuels) together with periodic measurements of fuel carbon content.

—*Tier 4:* Use CEMS. Use Tier 4 only for combustion units that have certain types of existing CEMS in place and that meet several other specific criteria, such as fuel type and hours of operation. Sources that have all of the necessary CEMS installed and certified by January 1, 2010 are required to use Tier 4 in 2010. However, for sources that need additional time to upgrade their CEMS, the use of CEMS can begin on January 1, 2011; and a lower tier calculation methodology may be used in 2010.

—As an alternative to any of the four tier methods, the rule provides that units that report to EPA year-round heat input data under 40 CRF part 75 can calculate CO_2 mass emissions using part 75 calculation methods.

• *Calculating CO_2 Emissions From Sorbent Use.* For fluidized bed boilers that use sorbent injection and units equipped with wet flue gas desulfurization systems, calculate CO_2 emissions from sorbent use using methods provided in the rule, except when CO_2 emissions are measured with CEMS.

• *Calculating CO_2 Emissions From Biomass Fuel Combustion.* Calculate CO_2 emissions from biomass combustion for only the specific types of biomass that are listed in the rule. The approach used for most units is to use a default high heat value and default CO_2 emission factor to estimate emissions. For determining the biomass fraction of CO_2 emissions from units that burn MSW or mixed fuels, and from units that co-fire biomass with fossil fuels and measure CO_2 emissions using CEMS, use the specific methods provided in the rule.

• *Calculating N_2O and CH_4 Emissions From Combustion.* Calculate N_2O and CH_4 emissions only for units that are required to report CO_2 emissions under this subpart and only for fuels for which default emission factors are provided in 40 CFR part 98, subpart C.

• *Fuel Sampling and Analysis.* The Tier 2 and Tier 3 calculation methodologies require periodic measurements of fuel heating value and carbon content. The minimum required frequency of these measurements is daily, weekly, monthly, quarterly, or semiannually, depending on the type of fuel combusted and other factors.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are needed for EPA verification of the reported GHG emissions from stationary combustion. The specific data to be reported are found in 40 CFR part 98, subpart C.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. These records are described in 40 CFR part 98, subpart C.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart C: General Stationary Fuel Combustion Sources.''

• Exemptions to GHG emissions reporting have been added for unconventional types of fuel. Reporters are required to calculate GHG emissions only for fuels that are listed in Table C–1 of subpart C, except that units larger than 250 mmBtu/hr, also must calculate GHG emissions for any other fuels that provide, on average, at least 10 percent of the annual heat input to the unit.

• The use of the Tier 2 calculation method for CO_2 emissions has been expanded to include units greater than 250 mmBtu/hr that combust only pipeline natural gas and/or distillate oil.

• Two new alternative methods have been added, allowing sources that monitor and report heat input according to 40 CFR part 75, but are not required to report CO_2 mass emissions, to use established Part 75 CO_2 emissions calculation methods to meet the 40 CFR part 98 reporting requirements.

• A definition of ''company records'', as it pertains to quantifying fuel consumption in Tiers 1, 2, and 3, has been added to 40 CFR 98.6.

• The required fuel sampling frequency in Tiers 2 and 3 has been reduced for many fuels, particularly those that are homogeneous or that are delivered in shipments or lots.

• Averaging of fuel sampling results is allowed for many fuels when the frequency of sampling and analysis is less than the minimum monthly frequency.

• The rule has been clarified to affirm that the use of fuel sampling results provided by the fuel supplier is permissible, and that the use of fuel billing records to quantify fuel consumption is also allowed.

• Additional deadline extensions for calibrating the fuel flow meters are provided in certain situations.

• The use of Tier 4 has been clarified; i.e., all of the conditions listed in 40 CFR 98.33(b)(4)(ii) and all of the conditions listed in 40 CFR 98.33(b)(4)(iii) must be met before Tier 4 is required.

• Units that must upgrade their existing CEMS to meet Tier 4 requirements may use either Tier 2 or Tier 3 in 2010.

• The methods for calculating CH_4 and N_2O emissions have been clarified.

• An expanded list of default emission factors are provided for certain solid, gaseous, and liquid biomass fuels.

• The use of steam production and combustion unit efficiency to calculate CO_2 emissions is extended to other solid fuels in addition to MSW. These parameters may also be used to quantify the amount of biomass combusted in a unit.

- The use of American Society for Testing and Materials (ASTM) Methods D7459–08 and D6866–06a to determine CO_2 emissions from combustion of mixed biomass fuels has been expanded to include the combustion of other biomass fuels in addition to those mixed with MSW.
- The missing data provisions have been made more flexible.
- The limit of 250 mmBtu/hr total heat input for aggregating units into groups for reporting purposes has been lifted.
- The reporting of combined units served by a common supply line, or common pipe configuration, has been clarified.
- The amount of required unit-level data and emissions verification information has been reduced for some of the measurement Tiers.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Many comments on general stationary fuel combustion were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart C: General Stationary Fuel Combustion Sources.''

Definition of Source Category

Comment: Several commenters asked EPA to clarify whether sources such as flares, hazardous waste incinerators, thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and small equipment such as stoves and space heaters are included in the stationary combustion source category. Others suggested that EPA should consider requiring that only the GHG emissions from combustion of traditional fossil fuels (if any) in these types of sources be reported.

Comments were also received on the proposed language for excluding emergency generators and the associated definitions.

Response: The final rule retains the broad definition of a stationary fuel combustion source, which is any device that combusts fuel. Fuel is defined very broadly to mean any combustible material. However, in evaluating public comments, we agree that in some cases the reporting of GHG emissions is unreasonable given the cost of monitoring and the relative level of GHG emissions. Monitoring can be particularly burdensome for vents with highly variable gas characteristics (e.g., carbon content and heat value). Accordingly, the final rule expands the list of combustion sources and fuels that are exempted from GHG emissions reporting under 40 CFR part 98, subpart C, as summarized below:

- Flares are exempted from 40 CFR part 98, subpart C. However, flares at some facilities might be covered by other subparts of the rule.
- Stationary combustion units that combust hazardous waste, as defined in 40 CFR 261.3, are also exempted. These units would report only the emissions from combustion of any fuels covered by subpart C that are co-fired with hazardous wastes.
- For calculations at the unit level, units less than 250 mmBtu/hour heat input are required to report GHG emissions only for fuels for which EPA has provided default emission factors in the rule.
- Units larger than 250 mmBtu/hour heat input GHG that combust miscellaneous, non-traditional fuels such as refinery gas, process gas, vent gases, waste liquids, and others must report only if CEMS are used or if these fuels contribute 10 percent or more of the annual unit heat input to the unit. With this exclusion, we have concluded that devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment would report only GHG emissions from the firing of supplemental fossil fuels.

In response to comments on the exclusion of emergency generators, EPA removed proposed language that would have required emergency generators to be identified as such in the facility's State or local air permit in order to qualify for an exemption. We also added language to exclude other emergency equipment. *See* Section III.D of this preamble for the response to the comments on exclusion of emergency generators from 40 CFR part 98, subparts C and D. *See* ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart A: Definitions, Incorporation by Reference, and Other Subpart A Comments'' for responses to comments on definitions, including changes to the emergency generator definition and the addition of a definition for emergency equipment.

Comment: Multiple commenters asked EPA to institute a ''*de minimis*'' provision in the rule to exclude stationary combustion sources other than the largest units at a facility.

Response: The final rule contains no *de minimis* exclusions. However, to simplify reporting, the rule allows small units to be aggregated and reported as a single emissions value, if certain conditions apply. The final rule has expanded the availability of this provision. The proposed rule limited the aggregation of any one group to a combined maximum capacity of 250 mmBtu/hour heat input. The final rule removes this limit and allows grouping of any units that individually are less than 250 mmBtu/hour heat input. EPA has also clarified the use of the common pipe metering option, so that all stationary combustion units at a facility using the same fuel that is metered through a common supply line may report a single emissions value under this rule. In addition, the changes listed above in Section III.C.2 of this preamble will simplify emissions calculations for many combustion units.

Method for Calculating GHG Emissions

Comment: EPA received numerous comments on the proposed GHG calculation methods for stationary combustion sources. Most of the comments centered on the use of the four-tiered approach for calculating CO_2 emissions. Several commenters requested that EPA remove the 250 mmBtu/hr unit size restriction on the use of Tier 1 and 2 calculation methods, especially for the combustion of relatively homogeneous fuels such as natural gas and fuel oil. Objections were raised to the specified frequency of fuel sampling under Tiers 2 and 3, as being excessive and unnecessary. Two commenters recommended that annual sampling be allowed for natural gas and fuel oil. A number of commenters asked the Agency to allow averaging of fuel sampling results (to simplify the CO_2 emissions calculations) and to affirm that the use of fuel sampling results provided by the fuel supplier is permissible. Others sought confirmation that fuel billing meters could be used to quantify fuel usage. Multiple commenters asked EPA to clarify who must use the Tier 4 calculation method, which requires the use of continuous emission monitoring systems (CEMS) to measure stack gas flow rate and CO_2 concentration. A number of comments were received requesting that sources currently monitoring and reporting heat input data under 40 CFR Part 75, but not reporting CO_2 mass emissions, be allowed to implement established Part 75 CO_2 emissions calculation methods in lieu of using Tiers 1 through 4. Finally, EPA received diverse comments on the proposed calculation method for CH_4 and N_2O emissions. Several commenters recommended that these emissions either not be reported at all, or that emissions reporting should be excluded for certain fuel types. Others asked for flexibility in determining the appropriate emission factors for CH_4 and N_2O. Some suggested that the use of operator-defined emission factors or factors from other GHG registries should be allowed.

Response: The final rule significantly expands the use of Tier 1 and Tier 2 calculation methodologies. All units rated at 250 mmBtu/hr or less are allowed to use the Tier 1 or Tier 2 calculation methodologies, depending on fuel sampling provisions at either the facility or by the supplier of the fuel. In addition, units rated at over 250 mmBtu/hr that combust pipeline quality natural gas and distillate oil are allowed to use the Tier 2 calculation methodology, because of the homogeneous nature and low variability in the characteristics of these fuels. However, the 250 mmBtu/hr unit size cutoff remains for units that combust residual oil, other gaseous fuels, and solid fossil fuel.

The mandatory monthly fuel sampling and analysis requirements for traditional fossil fuels have been dropped from Tiers 2 and 3. EPA agrees with the commenters that for a homogeneous fuel such as pipeline natural gas, monthly sampling is not necessary. Therefore, 40 CFR 98.34 has been revised to require that natural gas be sampled semiannually. For other fuels such as oil and coal, which are delivered in shipments or lots, requiring monthly sampling may be impractical, because new fuel lots or deliveries may not be received on a monthly basis. For fuel oil and coal, a representative sample is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For solid fuels other than coal, excluding MSW, weekly composite sampling with monthly analysis is required. For gaseous fuels other than natural gas and biogas, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required if such equipment for daily sampling is not installed.

The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, arithmetic averaging of higher heating value and carbon content data over the reporting year is permitted if these data are collected less frequently than monthly (*see* Equation C–2b in 40 CFR 98.33). However, regardless of the sampling frequency required by the rule, reporters must use the results of all available valid fuel analyses in the emissions calculations.

Today's rule clarifies the applicability of the Tier 4 methodology. Many commenters were unsure whether only one or all six of the conditions listed in proposed 40 CFR 98.33(b)(4)(ii) and all three of the conditions listed in proposed 40 CFR 98.33(b)(4)(iii) must be met to trigger the requirement to use CEMS. EPA's intent has always been that a source must meet all conditions listed in those sections to require the use of Tier 4. This has been made clear in the final rule text.

The final rule adds two methods that can be used as alternatives to any of the four tier calculation methods. These alternative methods apply to sources that are currently required to monitor and report heat input data according to 40 CFR part 75, but are not required to report CO_2 mass emissions. Many units subject to the Clean Air Interstate Regulation (CAIR) are in this category. These alternative methods allow these sources to use their 40 CFR part 75 heat input data together with one of the CO_2 emissions calculation methodologies in part 75 to meet 40 CFR part 98 CO_2 emissions reporting requirements. For instance, sources monitoring hourly heat input according to Appendix D of 40 CFR part 75 may use Equation G–4 in Appendix G of 40 CFR part 75 to calculate CO_2 emissions. Similarly, low mass emitting sources monitoring heat input under 40 CFR 75.19 may use Equation LM–11 in 40 CFR 75.19 to calculate CO_2 emissions. Sources using 40 CFR part 75 flow rate and CO_2 CEMS to continuously monitor heat input may use the CEMS measurements together with an appropriate equation from Appendix F of 40 CFR part 75 to determine CO_2 mass emissions.

The methodology for calculating CH_4 and N_2O emissions has been clarified in the final rule. Reporting of these emissions is required only for the fuels listed in Table C–2 of 40 CFR part 98, subpart C. Further, reporting of CH_4 and N_2O emissions is required only for units that are required to report CO_2 emissions under 40 CFR part 98, subpart C and only for fuels for which default emission factors are provided in subpart C. The emission factors in Table C–2 of 40 CFR part 98, subpart C are both fuel-specific and heat input-based. Therefore, when more than one type of fuel is combusted in a unit, direct measurements or engineering estimates of the annual heat input from each fuel are needed to calculate the CH_4 and N_2O emissions. Consequently, when CEMS (which are not fuel-specific) are used to monitor the CO_2 emissions and heat input for a multi-fuel unit, the total heat input measured by the CEMS must be apportioned to each fuel type. The owner or operator should use the best available information (e.g., fuel feed rates, high heat values) to do the necessary heat input apportionment. To provide greater consistency in reporting, EPA has chosen to retain the requirements for using the default factors in Table C–2 of 40 CFR part 98, subpart C, rather than allow reporters to select their own emission factors.

Procedures for Estimating Missing Data

Comment: EPA received several requests to modify the proposed missing data substitution procedures in 40 CFR part 98, subpart C. One commenter recommended that a minimum data capture requirement should be specified rather than requiring the use of substitute data to fill in missing data gaps. Another commenter suggested that only the ''before'' value be used for data substitution, rather than the average of the quality-assured values before and after the missing data period. Others favored using emission factors or the ''best available estimates'' for all parameters, rather than following a prescriptive missing data algorithm. Finally, several commenters asserted that 40 CFO part 75 missing data procedures for CO_2 are too conservative (i.e., may overestimate emissions significantly) and seem to be contrary to the objectives of 40 CFR part 98.

Response: The final rule provides additional flexibility to the missing data provisions of 40 CFR part 98, subpart C. The rule requires the use of ''before and after'' average values for only three parameters (fuel HHV, carbon content, and molecular weight). If the ''after'' value is not yet available when the GHG emissions report is due, the ''before'' value may be used for missing data substitution. For all other parameters, the reporter can substitute data values that are based on the best available estimates, based on all available process information.

EPA does not agree with the commenters who believe that the 40 CFR part 75 CO_2 missing data procedures are too conservative and contrary to 40 CFR part 98 program objectives. Nearly all 40 CFR part 75 sources maintain very high monitor data availability (95 percent or better) and use very little substitute data. Only when the data availability drops below 80 percent (which very seldom occurs) are the substitute data values significantly higher than the true CO_2 concentrations. Therefore, sources that monitor CO_2 emissions according to 40 CFR part 75 should continue to use the standard part 75 missing data provisions, and no adjustments to those substitute data values are deemed necessary for 40 CFR part 98 reporting purposes.

Data Reporting Requirements

Comment: A number of commenters objected to the amount of unit-level data and emissions verification information that is required to be reported electronically under 40 CFR 98.36 as ''burdensome'', ''unnecessary,'' and ''excessive.'' The commenters recommended that the auxiliary information should instead be kept on file and made available to EPA upon request. Several commenters recommended that EPA remove the 250 mmBtu/hr limit on the cumulative heat input capacity of units that can be aggregated into groups for reporting purposes. Other commenters asserted that EPA should consider the 40 CFR part 75 emissions data submitted under the ARP to be sufficient to satisfy 40 CFR part 98 requirements, and that there is no need to submit the same data twice.

Response: EPA does not agree with the assertion that the amount of unit-level data to be reported is excessive, burdensome, or unnecessary. For this mandatory GHG emissions reporting rule, two approaches to emissions data verification were considered, EPA verification and third-party verification. The Agency decided on EPA emissions verification. To verify GHG emissions estimates, EPA needs supporting data that are reported at the same level as the emissions are calculated. Because the rule requires that emissions be calculated at the unit level, it is imperative for EPA to obtain unit level verification data, particularly given the variety of requirements for estimating fuel combustion emissions under 40 CFR part 98, subpart C. Subpart C provides four different methods of estimating CO_2 emissions. The four methods require measurement of different parameters to estimate emissions, and the use of the methods is conditioned on a variety of operating factors. In addition, facilities use fuel combustion units of a variety of different sizes, types, and fuel firing scenarios. Under these circumstances, EPA could not verify that the correct methods were selected or applied correctly without unit-level data. If unit-level data were not submitted or were aggregated at a gross level, EPA could not reasonably verify the accuracy of reported facility-wide GHG emissions data, because EPA could not evaluate the relationship between unit capacity, fuel characteristics, fuel consumption, and emissions. However, as explained below, in the final rule EPA has made a number of significant adjustments to the data reporting requirements to clarify requirements and to reduce the reporting burden.

First, for units that use Tiers 1, 2 and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into groups has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in a group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same calculation methodology for any common fuels that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr using Tiers 1, 2, and 3 must report as individual units, unless they burn the same type of fuel and the fuel is provided by a common pipe or supply line. In that case, the owner or operator may opt to aggregate emission for all units fed by the common fuel line. Units using Tier 4 must report as individual units unless they share a monitored common stack.

Second, the rule requires minimal data to be reported for units that monitor and report emissions and heat input data according to 40 CFR part 75. Units that meet these criteria include units that are subject to the ARP, and potentially units that are subject to CAIR, and other programs. The final rule clarifies that 40 CFR part 75 sources must report 40 CFR part 98 GHG emissions data under the exact same unit, stack, or pipe ID numbers that are used for electronic reporting in the part 75 programs (e.g., 1, 2, CT5, CS001, MS1A, CP001, etc.). Even though most 40 CFR part 75 sources report CO_2 mass emissions data to EPA year-round, these data alone are not sufficient to satisfy the Part 98 reporting requirements for the following reasons. The emissions reports required under 40 CFR part 98 are facility-wide reports that require GHG emissions from all stationary combustion units at the facility, whether or not the units are subject to a 40 CFR part 75 program. Many electricity generating facilities have both ARP units and non-ARP units on site. Further, the CO_2 emissions data reported under 40 CFR part 75 are in units of short tons; Part 98 requires reporting in metric tons. Finally, 40 CFR part 98 also requires CH_4 and N_2O emissions to be reported, neither of which are reported under any 40 CFR part 75 program.

Third, the required verification data have been clarified and, in some cases, differ substantively from the proposed rule. No additional verification information is required for sources that monitor and report emissions and heat input data using 40 CFR part 75. This includes sources that elect to use the new alternative calculation methodologies for units monitoring heat input year round according to 40 CFR part 75 programs. For sources using Tiers 1, 2, 3, and 4, the final rule streamlines some of the reporting. Sources using Tier 3 are required to report only monthly averages of fuel carbon content and molecular weight rather than the proposed requirement to submit the results of each individual determination. Sources that use Tier 4 are required to report quarterly cumulative CO_2 mass emissions, rather than daily CO_2 emissions, as proposed. Also, to address concerns raised by some of the commenters, certain data elements need only be retained on file and provided to EPA upon request. These data elements include the methods used for fuel sampling and analysis, the methods used to calibrate fuel flow meters, the dates and results of fuel flow meter calibrations, and the dates and results of CEMS certification tests and on-going QA tests of the CEMS.

D. Electricity Generation

1. Summary of the Final Rule

Source Category Definition. This source category consists of EGUs that are subject to the ARP and any other EGUs that are required to monitor and report to EPA CO_2 mass emissions year-round according to 40 CFR part 75. All other EGUs are part of the general stationary fuel combustion source category and report under 40 CFR part 98 subpart C, if the facility meets the reporting rule applicability criteria. This source category excludes portable equipment, emergency generators, and emergency equipment.

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. Report annual CO_2, N_2O, and CH_4 mass emissions from each EGU.

GHG Emissions Calculation and Monitoring. For EGUs subject to the ARP and other EGUs that are required to monitor and report to EPA CO_2 mass emissions year-round according to 40

CFR part 75, the reporter must continue to monitor CO_2 emissions according to 40 CFR part 75. The cumulative CO_2 mass emissions reported in the fourth quarter electronic data reports must be converted from short tons to metric tons, for 40 CFR part 98 reporting purposes. The N_2O and CH_4 emissions must be calculated using fuel-specific default emission factors and heat input measurements in accordance with 40 CFR 98.33(c) in subpart C (General Stationary Fuel Combustion Sources).

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit unit-level data and other information that are used to verify the reported GHG emissions. The additional data and information to be reported for this source category are specified in 40 CFR 98.46.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. The specific records that must be retained for this source category are identified in 40 CFR 98.47.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart D: Electricity Generation.''

- The source category has been more precisely defined and includes only EGUs subject to the ARP and any other EGUs that are required to monitor and report to EPA CO_2 mass emissions year-round according to 40 CFR part 75.
- The proposed emergency generator exclusion language no longer requires that emergency generators be identified as such in State or local air permits.
- A CO_2 calculation methology was provided for units that are not in the ARP, but report CO_2 mass emissions year-round using 40 CFR part 75 methodologies.

3. Summary of Comments and Responses

Definition of Source Category

Comment: Several commenters were concerned that covering non-ARP EGUs in both subparts C and D of proposed 40 CFR part 98 was confusing and repetitive. Several commenters stated that the definition of an EGU is too inclusive and recommended that EPA revise it. The commenters were concerned that any unit, regardless of electrical output, could be identified as an EGU and place a facility in the electricity generation source category. One commenter suggested that a 25 megawatts (MW) threshold should be added to the EGU definition in 40 CFR 98.6 and to 40 CFR part 98, subpart D. A multitude of commenters objected to the language in proposed 40 CFR 98.40 requiring emergency generators to be designated as such in a State or local air permit, in order for the generators to be exempted from GHG emissions reporting. Many of these same commenters recommended changes to the definition of ''emergency generator'' in 40 CFR 98.6, suggesting that the term ''generator'' should be replaced with the term ''reciprocating internal combustion engine (RICE)'', to be consistent with 40 CFR 63.6675, subpart ZZZZ. Others recommended that EPA should also exempt emergency equipment such as fire pumps, fans, etc. from GHG emissions reporting.

Response: The electricity generation source category definition in subpart D (40 CFR 98.40) has been modified based on the comments received. The final rule limits the source category to EGUs that are subject to ARP and to other EGUs that monitor and report to EPA CO_2 mass emissions year-round according to 40 CFR part 75. The final subpart D does not cover any other EGUs. The GHG emissions from other EGUs are covered under subpart C (General Stationary Fuel Combustion).

The definition of an ''emergency generator'' in 40 CFR 98.6, the final rule has been changed to clarify that it includes both RICE and turbines. EPA has also added a definition of ''emergency equipment'' to 40 CFR 98.6, and exempts such equipment from GHG emissions reporting under both 40 CFR part 98, subparts C and D.

The proposed requirements in 40 CFR part 98, subparts C and D for emergency generators to be identified as such in State and local air permits in order to be exempt from GHG emissions reporting has been revised. There is considerable variation from State to State regarding the regulation of emergency generators, including whether or not permits are required. Some States specifically exempt emergency generators from permitting requirements. Other States use a permit by rule approach for emergency units. In view of this, the Agency has revised the wording of the exclusion for emergency generators to allow for situations where they are not specifically identified in a facility's permit.

Method for Calculating GHG Emissions

Comment: Several commenters suggested that for units that are not in the ARP but are required by other regulatory programs to report part 75 emissions and heat input data, EPA should expand the four-tiered calculation method for CO_2 mass emissions in 40 CFR 98.33(a) to allow the use of CO_2 emissions calculation methods based on Appendices D and G of part 75.

Response: The electricity generation source category definition has been narrowed to only include EGUs that are subject to ARP and to other EGUs that monitor and report to EPA CO_2 mass emissions year-round according to 40 CFR part 75 (e.g., RGGI units). The final subpart D provides a CO_2 calculation methodology for such EGUs that are not in the ARP, but report to EPA CO_2 mass emissions year-round using part 75 methodologies. For the purposes of part 98, the CO_2 emissions from these units are calculated and reported using the same methods as part 75.

Other units that are not in the ARP but report data under part 75, subpart C are now covered by 40 CFR part 98, subpart C instead of subpart D, and subpart C has been revised to allow the use of part 75 calculation methodologies. The response to the comment on these units is contained in Section III.C of this preamble (General Stationary Fuel Combustion Sources).

E. Adipic Acid Production

1. Summary of the Final Rule

Source Category Definition. The adipic acid production source category consists of all processes that use oxidation to produce adipic acid.

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. Report N_2O process emissions from adipic acid production.

In addition, report GHG emissions for other source categories at the facility for which calculation methods are provided in the rule, as applicable. For example, report CO_2, N_2O, and CH_4 emissions from each stationary combustion unit on site under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

GHG Emissions Calculation and Monitoring. Unless an alternative method of determining N_2O emissions is requested, calculate N_2O process emissions from adipic acid production by multiplying a facility-specific emission factor by the annual adipic acid production level. Determine the facility-specific emission factor by an annual performance test to measure N_2O emissions from the waste gas stream of each oxidation process and the production rate recorded during the test.

When N_2O abatement devices (such as nonselective catalytic reduction) are used, adjust the N_2O process emissions for the amount of N_2O removed using the destruction efficiency for the control device and the fraction of annual production for which the control device is operating. The destruction efficiency can be specified by the abatement device manufacturer or can be determined using process knowledge or another performance test.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart E.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart E.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found in this section or ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart E: Adipic Acid Production.''

- The re-testing trigger was changed. Performance testing to determine the N_2O emissions factor is required annually, whenever the ratio of cyclohexanone to cyclohexanol is changed, and when new abatement equipment is installed.
- Equation E–2 was edited to correct a calculation error and to allow multiple types of abatement technologies.
- 40 CFR 98.56 was reorganized and updated to improve the data reporting requirements as needed for the emissions verification process. Some data elements were moved from 40 CFR 98.57 to 40 CFR 98.56, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.53 were added to 40 CFR 98.56 for clarity.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments on adipic acid production were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart E: Adipic Acid Production.''

GHGs To Report

Comment: Multiple commenters asked that the language in 40 CFR 98.52(b) be clarified to include emissions under 40 CFR part 98, subpart E only from units that are 100 percent dedicated to adipic acid production to avoid double counting of combustion emissions.

Response: We reviewed this issue but decided not to make any changes to 40 CFR part 98, subpart E. We do not foresee a potential for double counting of combustion emissions at the facility because all combustion unit emissions at adipic acid facilities are to be reported under 40 CFR part 98, subpart C. 40 CFR part 98, subpart E provides methods for reporting only the process N_2O emissions. Also see Section III.C of this preamble for responses to comments related to 40 CFR part 98, subpart C (General Stationary Combustion).

Selection of Proposed GHG Emissions Calculations and Monitoring Methods

Comment: One commenter stated that emissions of N_2O do not correlate with the production of adipic acid at their facility. A portion of the process off gas, which contains N_2O, is sold to an offsite facility via dedicated piping. The amount sold depends on customer needs and the amount is metered. The commenter asked that the language in the final rule address this issue.

Response: We agree that N_2O emitted from the production of adipic acid that is sold or transferred offsite is not covered in the proposed rule. The final rule has been changed to require this amount of N_2O to be reported. Allowing for this additional reporting requirement ensures that the reported N_2O emissions attributed to the adipic acid facility are accurate. Reporting of the N_2O sold or transferred offsite will help EPA improve methodologies for reporting of GHG emissions.

Method for Calculating GHG Emissions

Comment: Multiple commenters asked that the requirement to repeat the annual performance test be removed. In the proposal, re-testing was triggered whenever the adipic acid production rate changed by more than 10 percent. Commenters asserted that production depends on demand for adipic acid and often varies by 15 percent.

Response: Upon review, we decided to eliminate re-testing. We believe that annual determination of the N_2O emissions factor is sufficient to accurately calculate N_2O emissions as long as the production equipment remains consistent over the year-long period (i.e. no new abatement technology).

Comment: Multiple commenters asked that alternative methods be allowed for calculating N_2O emissions from adipic acid production. Specifically the commenters asked that EPA allow the use of N_2O and flow CEMS to directly measure N_2O emissions and use the performance test to evaluate the CEMS accuracy. The commenters also asked that EPA allow the use of existing process flow meters and process N_2O analyzers to determine the amount of N_2O sent to control devices and use the performance test to measure control device destruction efficiency.

Response: We agree that there are other means of determining site-specific N_2O emissions. The final rule has been changed to allow alternative test methods. Any alternative must be approved by the Administrator before being used to comply with this rule. An implementation plan that details how the alternative method will be implemented must be included in the request for the alternative method. Until the method is approved facilities must use the alternatives proposed in the rule for a performance test. As one commenter noted, at minimum the performance test will help to QA/QC alternative methods currently used to monitor N_2O emissions (such as N_2O CEMS).

EPA understands the need to further evaluate and establish alternative comparable methods for sources to use in accurately calculating N_2O emissions from adipic production and will address in future rulemakings or amendments to rulemaking.

The final rule does allow the use of existing process flow meters and process knowledge in the determination of the destruction factor of N_2O abatement technologies. This parameter is often based on site-specific knowledge and operations. We believe that using existing methods can also reduce the potential cost impacts of this rulemaking and that it is in the best interest of the facilities that process parameters be accurately measured.

Comment: One commenter asked that Equation E–2 be edited to follow the summation format used in the IPCC Tier 2 methodology. The current format does not allow for multiple abatement technologies (including no abatement).

Response: We agree with the commenter. The equation in the proposed rule contained an error and did not allow for multiple abatement technologies. The final rule contains a corrected version of the equation.

F. Aluminum Production

1. Summary of the Final Rule

Source Category Definition. The aluminum production source category consists of facilities that manufacture primary aluminum using the Hall-Héroult manufacturing process. The primary aluminum manufacturing process consists of the following operations:

- Electrolysis in prebake and Søderberg cells.
- Anode baking for prebake cells.

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. For aluminum production, report:

- Perfluoromethane (CF_4) emissions and perfluoroethane (C_2F_6) emissions from anode effects in all prebake and Søderberg electrolysis cells combined.
- CO_2 emissions from anode consumption during electrolysis in all prebake and Søderberg cells.
- All CO_2 emissions from anode baking.

In addition, report GHG emissions for other source categories at the facility for which calculation methods are provided in the rule, as applicable. For example, report CO_2, N_2O, and CH_4 emissions from each stationary combustion unit on site under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

GHG Emissions Calculation and Monitoring. Reporters must calculate process emissions using the following methods:

- *CF_4 from anode effects:* Calculate annual CF_4 emissions based on the frequency and duration of anode effects in the aluminum electrolytic reduction process for each prebake and Søderberg electrolysis cell using the following parameters:

—Anode effect minutes (AEM) per cell-day calculated monthly.
—Aluminum metal production calculated monthly.
—A slope coefficient relating CF_4 emissions to anode effect minutes per cell-day and aluminum production. The slope coefficient is specific to each smelter and must be measured in accordance with the protocol specified in the rule at least once every 10 years.
—Facilities are allowed to use historic smelter-specific slope coefficients for the first three years of reporting under the rule. Historic measurements include all those made under EPA's Voluntary Aluminum Industry Partnership or at facilities owned or operated by companies participating in the Voluntary Aluminum Industry Partnership. Facilities without historic measurements are required to complete measurements by the end of first year of reporting.
—Facilities which operate at less than 0.2 anode effect minutes per cell day or, when overvoltage is recorded, operate with less than 1.4mV overvoltage, can use either smelter-specific measured slope coefficients or the technology-specific (Tier 2) default coefficients from Volume III, Chapter 4, Section 4.4 Metal Industry Emissions of the 2006 IPCC Guidelines for National Greenhouse Gas Inventories as specified in the rule.

- *C_2F_6 from anode effects:* Calculate annual C_2F_6 emissions from anode effects from each prebake and Søderberg electrolysis cell using the calculated CF_4 emissions and the mass ratio of C_2F_6 to CF_4 emissions, as determined during the same test during which the slope coefficient is determined.
- *Process CO_2 emissions—general approaches.* Most reporters can elect to calculate and report process CO_2 emissions from anode consumption during electrolysis and from anode baking by either (1) installing and operating CEMS and following the Tier 4 methodology (in 40 CFR part 98, subpart C) or (2) using the calculation procedures specified below.
- However, if process CO_2 emissions from anode consumption during electrolysis or anode baking are emitted through the same stack as a combustion unit or process equipment that uses a CEMS and follows Tier 4 methodology to report CO_2 emissions, then the CEMS must be used to measure and report combined CO_2 emissions from that stack, instead of using the calculation procedures specified below.
- *CO_2 emissions from anode consumption in prebake cells:* Calculate annual CO_2 emissions at the facility level using a mass balance equation based on measurements of the following parameters:

—Net prebaked anode consumption rate per metric ton of aluminum metal produced.
—Ash and sulfur contents of the anodes.
—Total mass of aluminum metal produced per year for all prebake cells.

- *CO_2 emissions from Søderberg cells:* Calculate CO_2 emissions from paste consumption in Søderberg cells using a mass balance equation at the facility level based on the following parameters:

—Paste consumption rate per metric ton of aluminum metal produced and the total mass of aluminum metal produced per year for all Søderberg cells.
—Emissions of cyclohexane-soluble matter per metric ton of aluminum produced.
—Binder content of the anode paste.
—Sulfur, ash, and hydrogen contents of the coal tar pitch used as the binder in the anode paste.
—Sulfur and ash contents of the calcined coke used in the anode paste.
—Carbon in the skimmed dust from the cell, per metric ton of aluminum produced.

- *CO_2 emissions from anode baking of prebake cells:* Calculate CO_2 emissions at the facility level separately for pitch volatiles combustion and for bake furnace packing material.
- To calculate CO_2 emissions from the pitch volatiles, use a mass balance equation based on the following parameters:

—Initial weight of the green anodes.
—Mass of hydrogen in the green anodes.
—Mass of the baked anodes.
—Mass of waste tar collected.

- To calculate CO_2 emissions from bake furnace packing material, use a mass balance equation based on the following parameters:

—Packing coke consumption rate per metric ton of baked anode production.
—Sulfur and ash contents of the packing coke.

- The variables used to calculate CO_2 emissions from anode and paste consumption (e.g., sulfur, ash, and hydrogen contents) can be determined for each facility, or the source can use default values from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories as specified in 40 CFR 98.64.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart F.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart F.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart F: Aluminum Production.''

- A new subsection was added in 40 CFR 98.63 providing a new equation (Eq. F–1) to sum monthly PFC emission values into annual PFC emission value.
- The equation for CO_2 emissions from Søderberg cells (paste consumption) was corrected.
- Language was updated to request reporting of all CO_2 emissions from on-site anode baking.
- Language was updated to request reporting of smelter-specific slope coefficients (plural).
- A new equation was added in 40 CFR 98.63 (Eq. F–3) to calculate CF_4 emissions from overvoltage; and updated language in subsequent sections to accommodate the overvoltage method.
- Language was added to permit facilities that operate with low anode effect minutes or low overvoltages to use IPCC Tier 2 default slope factors.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Three comments on aluminum production were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart F: Aluminum Production.''

Comment: Several commenters suggested that smelters should be permitted to use International Aluminum Institute default slope coefficients which are based on global technology-specific averages to calculate PFC emissions, especially at high performance facilities.

Response: The use of smelter-specific slope coefficients as required in the rule leads to significantly more precise PFC emission calculations than the use of default slope coefficients (95 percent confidence interval of ±15 compared to ±50 percent). For a typical U.S. smelter emitting 175,000 metric tons of CO_2-eq in PFCs, these errors result in absolute uncertainties of ±88,000 $MTCO_2e$ and ±26,000 $MTCO_2e$, respectively. The reduction in uncertainty associated with moving from default to smelter-specific slope coefficients, 62,000 $MTCO_2e$, is as large as the emissions from many of the sources that would be subject to the rule. However, for ''high performance'' facilities, which are defined by the 2006 IPCC Guidelines as those at or below 0.2 anode effect minutes per cell day or less than 1.4 mV overvoltage, the IPCC analysis indicates that impact of moving from a Tier 2 to a Tier 3 slope coefficient would not result in a significant improvement in PFC emissions. Therefore, EPA agrees that high performance facilities should be allowed to use technology specific (Tier 2) default values from Volume III, Chapter 4, Section 4.4 Metal Industry Emissions of the 2006 IPCC Guidelines for National Greenhouse Gas Inventories. These values are identical to the ''Aluminum Sector Greenhouse Gas Protocol (Addendum to the WRI/WBCSD Greenhouse Gas Protocol),'' October 2006 default coefficients.

Comment: Several commenters argued the requirement to re-measure smelter-specific slope coefficients every three years is expensive and unnecessary.

Response: While the cost to require smelter-specific slope coefficients is significantly greater than the cost to use default slope coefficients, the benefit of reduced uncertainty is considerable, as noted above. The costs that would be incurred by smelters measuring slope factors are discussed in the Regulatory Impact Analysis (RIA) for the proposed rulemaking (EPA–HQ–OAR–2008–0508–002).

Of the currently operating U.S. smelters, all but one has measured a smelter specific coefficient at least once; and at least three used the 2003 EPA/IAI protocol for measuring smelter-specific slope coefficients.

The *USEPA/IAI Protocol for Measurement of Tetrafluoromethane and Hexafluoroethane from Primary Aluminum Production* establishes guidelines to ensure that measurements of smelter-specific slope-coefficients are consistent and accurate (e.g., representative of typical smelter operating conditions and emission rates). The Protocol currently recommends that smelter operators re-measure their slope coefficients at least every three years, and more frequently if they adopt changes to process control algorithms or observe changes to typical anode effect duration. Specifically, the Protocol recommends that operators repeat measurements of slope coefficients for CF_4 and C_2F_6 if one or more of the following apply: (1) Thirty-six months have passed since the last measurements (i.e., triennial measurements are recommended); (2) a change occurs in the control algorithm that affects the mix of types of anode effects or the nature of the anode effect termination routine; and, (3) changes occur in the distribution of duration of anode effects (e.g. when the percentage of manual kills changes or if, over time, the number of anode effects decreases and results in a fewer number of longer anode effects).

Changes to process control algorithms or to the typical duration of anode effects can change the relationship between anode effect minutes, production, and emissions, that is, they can change slope coefficients. In addition, more subtle changes can also change slope coefficients over time. According to industry experts, the rate of these more subtle changes has not been sufficiently studied to specify a frequency for re-measurement nor have there been a sufficient number of facilities that have been measured repeatedly to document the benefit of the additional incremental cost of measurement once every three years.

During the past few years, multiple U.S. smelters have adopted changes to their production process which are likely to have changed their slope coefficients. These include the adoption of slotted anodes and improvements to process control algorithms. Although some U.S. smelters have recently updated their measurements of smelter-specific coefficients, others may not have.

In view of these recent process changes, EPA is requiring smelters that have not already measured their slope factors under the ''2008 USEPA/IAI Protocol for Measurement of Tetrafluoromethane and Hexafluoroethane from Primary Aluminum Production,'' to do so in time for the 2013 reporting year. EPA believes that this will ensure that slope factors are appropriately updated while providing sufficient lead-time for smelters to perform the measurements without encountering excessive costs or logistical barriers. However, after this initial update, EPA agrees that every three years is burdensome, therefore, further updates are required only every ten years unless there are major technological or process changes at a facility such as changes to the control algorithm that affect the mix of types of anode effects or the nature of the anode effect termination routine; or changes occur in the distribution of duration of anode effects (e.g. when the percentage of manual kills changes or if, over time, the number of anode effects decreases and results in a fewer number of longer anode effects).

Comment: Several commenters suggested that the rule should include the overvoltage measurement method, which is specific to use with Pechiney technology, in case one or more U.S. smelters decide to adopt this technology in the future.

Response: The Overvoltage Method relates PFC emissions to an overvoltage coefficient, anode effect overvoltage, current efficiency, and aluminum production. The overvoltage method was developed for smelters using the Pechiney technology. While it is EPA's understanding that no U.S. smelters have used the Pechiney technology for at least a decade, if one or more U.S. smelters decide to adopt this internationally accepted technology in the future they would be expected to use the overvoltage method which follow the established guidelines in the ''USEPA/IAI Protocol for Measurement of Tetrafluoromethane and Hexafluoroethane from Primary Aluminum Production.''

G. Ammonia Manufacturing

1. Summary of the Final Rule

Source Category Definition. The ammonia manufacturing source category consists of process units in which ammonia is manufactured from a fossil-based feedstock via steam reforming of the hydrocarbon. It also includes ammonia manufacturing processes in which ammonia is manufactured through the gasification of solid and liquid raw material.

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. For ammonia manufacturing, report the following emissions:

- CO_2 process emissions from steam reforming of a hydrocarbon or the gasification of solid and liquid raw material, reported for each ammonia manufacturing process unit following the requirements of this part.
- CO_2, CH_4, and N_2O emissions from each stationary combustion unit. Report these emissions under 40 CFR 98, subpart C (General Stationary Fuel Combustion Sources) by following the requirements of 40 CFR part 98, subpart C.
- For CO_2 collected and transferred off site, report these emissions under 40 CFR part 98, subpart PP (Suppliers of CO_2) following the requirements of 40 CFR part 98, subpart PP.

In addition, report GHG emissions for any other source categories at the facility for which calculation methods are provided in other subparts of the rule, as applicable.

GHG Emissions Calculation and Monitoring. Reporters must use one of two methods to calculate CO_2 process emissions, as appropriate:

- Most reporters can elect to calculate and report process CO_2 emissions from each ammonia manufacturing process unit by either (1) installing and operating CEMS and following the Tier 4 methodology (in 40 CFR part 98, subpart C) or (2) using the calculation procedures contained in the rule and summarized below.
- However, if process CO_2 emissions from an ammonia manufacturing process unit are emitted through the same stack as CO_2 emissions from a combustion unit or process equipment that uses a CEMS and follows Tier 4 methodology to report CO_2 emissions, then the CEMS must be used to measure and report combined emissions from that stack, instead of using the calculation procedures described below.
- To calculate process CO_2 emissions, use the equations provided in 40 CFR part 98, subpart G for solid, liquid, and gaseous feedstock and the following measurements:

—Continuous measurement of gaseous or liquid feedstock consumed using a flowmeter, or monthly aggregate of solid feedstock consumed.

—Carbon content of the feedstock (required to be measured monthly using supplier data or analysis using the appropriate test methods). If supplier data are used, facilities must QA/QC the supplier analysis on an annual basis using the appropriate test methods.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart G.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart G.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart G: Ammonia Manufacturing.''

- Monitoring and QA/QC requirements were revised to allow for obtaining carbon content of feedstock used in ammonia manufacturing from the feedstock supplier. Facilities that obtain monthly carbon content information from their supplier are required to QA/QC supplier information through annual sampling and analysis of the feedstock.
- Missing data procedures were added under 40 CFR 98.75 for parameters that facilities must measure such as feedstock consumption, the quantity of the waste recycle stream, and the monthly carbon content of both the feedstock consumption and waste recycle stream quantity.
- Reporting requirements were added for the quantity of urea produced and the emissions associated with waste recycle streams commonly found at ammonia manufacturing facilities.
- 40 CFR 98.76 was reorganized and updated to improve the emissions data verification process. Some data elements were moved from 40 CFR 98.77 to 40 CFR 98.76, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.73 were added to 40 CFR 98.76 for clarity.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments on ammonia manufacturing were received covering numerous topics. Several of these comments were directed at the requirements for 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources), and responses to those comments are provided in Section III.C of this preamble. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to

Public Comments, Subpart G: Ammonia Manufacturing.''

Method for Calculating GHG Emissions

Comment: Several commenters asked EPA to clarify that ammonia production units must use Tier 4 calculation only if all of the conditions under proposed 40 CFR 98.33(b)(5)(ii)(A) through (F) apply to the unit and only where the ammonia manufacturing unit already has installed a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

Response: We agree with the comment and have modified the text under 40 CFR 98.73(a) and (b) to state that if a facility operates and maintains CEMS that meet the requirements of 40 CFR 98.33(b)(4)(ii) or (iii), then process or combined process and combustion CO_2 emissions shall be calculated and reported under this subpart by following the Tier 4 Calculation Methodology specified in 40 CFR 98.33(a)(4) and all associated requirements for Tier 4 in 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources). If CEMS are not used to determine CO_2 emissions from ammonia processing units, then facilities must calculate and report process CO_2 emissions under this subpart by using equations provided in 40 CFR 98.73(b)(1) through (b)(4). CO_2 combustion emissions from ammonia processing units must be reported under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources). For additional clarification on the requirements on use of CEMS see 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources), and Section III.C of this preamble.

Comment: One commenter noted that most ammonia facilities utilize natural gas combustion combined with approximately five percent recycle flow of gas containing methane from the process. The carbon content of the recycle stream is already accounted for when measuring the feedstock flow rate and carbon content to the process. EPA should allow ammonia manufacturers to exclude this recycle stream in calculating combustion emissions, as the carbon in the recycle stream would be double counted.

Response: We agreed with commenters that it is important to account for use of the waste process stream in the case that it is recycled since carbon in the recycle stream is not actually emitted. In response to this comment we have added reporting requirements for quantifying emissions associated with the recycle stream. This will help EPA improve methodologies for calculating emissions from ammonia manufacturing in the future.

Monitoring and QA/QC Requirements

Comment: Several commenters stated that monthly carbon content sampling and analysis requirement is overly burdensome. Some commenters asked that EPA allow the use of a default value for carbon content while one commenter suggested use of carbon content data generated by the feedstock supplier.

Response: We agreed with commenters that flexibility should be added to the rule to allow for use of supplier data. This information is readily available from the feedstock supplier in most cases. The most common feedstock for ammonia production is pipeline quality natural gas. Supplier data on carbon contents of feedstock will have sufficient or comparable accuracy for the purposes of calculating CO_2 emissions. We modified the monitoring and QA/QC procedures in the rule to allow use of carbon content data obtained from the feedstock supplier(s). Facilities that obtain monthly carbon content information from their supplier are required to QA/QC supplier information through annual sampling and analysis of the feedstocks consumed.

Procedures for Missing Data

Comment: Two commenters suggested that the proposed procedures for calculating emissions in the event of missing feedstock data would yield significant overstatements of GHG emissions. As proposed, if feedstock supply rate data are missing for a specific day or days (e.g., if a meter malfunctions during unit operation), the reporting entity must use the lesser of the maximum supply rate that the production unit is capable of processing or the maximum supply rate that the meter can measure. If this substitution is applied to the feedstock for reformers used in ammonia production, either of these proposed approaches would likely result in significant over reporting of carbon emissions. The commenter proposed two alternatives that a reporting facility could use: Either (1) substitute an estimated value for feedstock supply rate, based on the arithmetic average of the previous thirty days of available feedstock supply rate data; or (2) utilize missing data estimating procedures similar to the procedure under 40 CFR 98.35(b)(2), based upon all available process data. These approaches would result in much more accurate estimates of emissions derived from the true historical operation of a specific ammonia manufacturing source.

Response: We agreed with commenters that the proposed missing data procedures would overestimate emissions when applied. While some of feedstock should be readily available and collected as a part of normal business practices, circumstances could arise where data could be missing. We added procedures consistent with the commenter's second recommendation, referencing the missing data procedures in 98.35(b)(2). Ammonia facilities with missing data on feedstock supply rate must provide the best available estimate from all available process data. Facilities must document and keep records of missing data procedures applied. We find that these revised procedures will provide accurate information for the purposes of this rulemaking.

Data To Be Reported

Comment: One commenter noted that the CO_2 produced through ammonia manufacturing can be utilized and that much of it is in the manufacture of urea. The commenter stated that EPA makes unsubstantiated assumptions that all CO_2 in urea will be released into the atmosphere. The commenter asked EPA not to tie emissions from applied urea, or emissions that result from urea once the product has been sold, to the producing industry.

Response: We added reporting requirements for annual urea production under 40 CFR 98.76. Information on urea production will help us improve our understanding of the quantity of CO_2 consumed from ammonia production that is used in the manufacture of urea. We know from the US GHG inventory and subsequent conversations with ammonia producers that on average it takes 0.733 tons of CO_2 to produce one ton of urea. We have also requested that producers report, if known, the uses of the urea sold. Collecting information on urea production and its uses will help EPA to improve methodologies for calculating emissions from ammonia manufacturing, urea production, and urea consumption in the future.

H. Cement Production

1. Summary of the Final Rule

Source Category Definition. The cement production source category consists of each kiln and each inline kiln/raw mill at any Portland cement manufacturing facility, including alkali bypasses and kilns and inline kilns/raw mills that burn hazardous waste.

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. For cement production, report the following emissions:

- CO_2 process emissions from calcination, reported for each kiln.
- CO_2 combustion emissions from each kiln.
- N_2O and CH_4 emissions from fuel combustion at each kiln under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources) using the methodologies in subpart C.
- CO_2, N_2O, and CH_4 emissions from each stationary combustion unit other than kilns under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).
- In addition, report GHG emissions for any other source categories for which calculation methods are provided in other subparts of the rule, as applicable.

GHG Emissions Calculation and Monitoring. For CO_2 emissions from kilns, reporters must select one of two methods, as appropriate:

- For kilns with certain types of CEMS in place, reporters must use the CEMS and follow the Tier 4 methodology (in 40 CFR part 98, subpart C) to measure and report under the Cement Production subpart (40 CFR part 98, subpart H) combined calcination and fuel combustion CO_2 emissions.
- For other kilns, the reporter can elect to either (1) install or operate a CEMS and follow the Tier 4 methodology to measure and report combined calcination and fuel combustion CO_2 emissions or (2) calculate process CO_2 emissions as the sum of clinker emissions and emissions from raw materials. If using approach (2):

—Calculate clinker emissions monthly from each kiln using monthly clinker production (required to be measured); a kiln-specific, monthly clinker emission factor calculated from the monthly CaO and MgO content of the clinker (required to be measured); quarterly cement kiln dust not recycled to the kiln (required to be measured); and a quarterly kiln-specific factor of calcined material in the cement kiln dust not recycled to the kiln (measured or default values can be used).

—Calculate raw material emissions annually from the annual consumption of raw materials and the organic carbon content in the raw material (measured annually for each type of raw material, or a default value of 0.2 percent may be used).

—Report process CO_2 emissions from each kiln under 40 CFR part 98, subpart H (Cement Production), and report combustion CO_2 emissions from each kiln under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, Subpart H (Cement Production).

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart H (Cement Production).

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart H: Cement Production.''

- The CO_2 calculation equations in 40 CFR 98.83 were revised to account for non-carbonate sources of calcium and magnesium in the kiln feed and uncalcined carbonates in the product.
- Methods for monitoring CaO and MgO in clinker and CKD were changed from XRF to ASTM c114–07, Standard Test Methods for Chemical Analysis of Hydraulic Cement.
- 40 CFR 98.84 was revised to clarify required monitoring frequency and to allow for alternative monitoring methods for raw materials and CKD.
- Missing data procedures were added to 40 CFR 98.85 for parameters reporters must measure, clinker, CKD not recycled to the kiln, raw material consumption, carbonate contents of clinker CKD, non-calcined content of clinker and CKD, and organic carbon content of raw materials.
- Requirements in 40 CFR 98.81 through 40 CFR 98.87 were revised to clarify which requirements apply to reporters who elect to report CO_2 emissions using CEMS.
- 40 CFR 98.86 was reorganized and updated to improve the emissions verification process. Some data elements were moved from 40 CFR 98.87 to 40 CFR 98.86, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.83 were added to 40 CFR 98.86 for clarity.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. We received several comments on cement production covering a number of topics. Many of these comments were directed at the requirements for 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources), and responses to those comments are provided in Section III.C of this preamble dealing with that source category. *Also see* Section II.N of this preamble for the response to comments on the emissions verification approach.

Responses to significant comments received related to process emissions from cement production can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart H: Cement Production.''

Selection of Threshold

Comment: One commenter suggested that EPA could reduce the burden presented by the Proposed Rule by reducing the number of facilities required to report (i.e., raise the reporting thresholds). The commenter further noted that by requiring GHG reporting for all cement plants, regardless of the magnitude of the plant's emissions, EPA removes an incentive for those plants to reduce GHG emissions to get below a threshold in order to avoid the burden of monitoring and reporting.

Response: In considering the comment, we acknowledge the potential benefit of a reporting threshold providing cement plants with incentive to reduce their GHG emissions. The ''once in, always in'' provision has been removed. The final rule now contains provisions to cease reporting if annual reports demonstrate emissions less than specified levels for multiple years. These provisions apply to all reporting facilities. *See* Section II.H of this preamble for the response on provisions to cease reporting. *See* Section II.D of this preamble for the response on selection of source categories to report.

In developing the Proposed Rule, we considered emission-based thresholds of 1,000 metric tons CO_2e, 10,000 metric tons CO_2e, 25,000 metric tons CO_2e, and 100,000 metric tons CO_2e. All of these emission thresholds covered more than 99.9 percent of CO_2e emissions from cement facilities. Only one plant out of 107 in the dataset would be excluded by the highest considered thresholds of 100,000 metric tons CO_2e. Therefore, we determined that it was appropriate to include all cement production facilities in the reporting requirements.

Method for Calculating GHG Emissions

Comment: Two commenters stated that the cement industry already has an established, proven protocol for calculating and reporting GHG emissions, and requested that EPA use the existing Cement CO_2 Protocol as the basis for the Proposed Rule. Commenters further stated that the Cement CO_2 Protocol already provides many of the benefits that EPA ascribes to the Proposed Rule, including uniformity of reported data from one facility to another; availability of verifiable data to provide to the public, investors, and others; and other suggested benefits.

Both commenters stated that EPA needs to revise its clinker-based calculation to account for any non-carbonated CaO or MgO in the raw materials.

Response: In developing the proposed Rule, we considered many domestic and international GHG monitoring guidelines and protocols, including the Cement Sustainability Initiative Protocol referenced in the cement industry's comments. We combined elements of the Cement CO_2 Protocol with elements of other protocols including the 2006 IPCC Guidelines, U.S. Inventory, DOE 1605(b), CARB mandatory GHG emissions reporting program, EPA's Climate Leaders program, and the EU Emissions Trading System to develop two proposed methods for quantifying GHG emissions from cement manufacturing. These proposed methods include the use of CEMS to directly measure emissions and the use of calculation methods to determine emissions.

While finalizing today's rule, we revisited the Cement CO_2 Protocol and compared its requirements to our requirements. We feel that the rule closely mirrors the GHG calculation methods and requirements of the Cement CO_2 Protocol with some minor differences. For example, our rule requires cement plants to use plant-specific emission factors to calculate CO_2 emissions and does not allow the use of default emission factors. As stated in the proposal, we have determined that applying default emission factors to clinker production is more appropriate for national-level emissions estimates than facility-specific estimates, where data are readily available to develop site-specific emission factors. Default approaches would not provide site-specific calculation of emissions that reflect differences in inputs, operating conditions, fuel combustion efficiency, variability in fuels, and other differences among facilities. Further, it is our understanding that facilities analyze data relevant for site-specific determinations such as the carbonate contents of their raw materials to the kiln and products on a frequent basis, either on a daily basis or every time there is a change in the raw material mix. Using data from direct measurements will provide a more accurate representation of site specific emissions rates.

We also note that the Cement CO_2 Protocol does not specify measurement methods. Our rule specifies methods for measuring CaO, MgO, and clinker weight. We selected these methods to be consistent with measurement techniques that are common within the cement industry. Prescribing standardized measurement procedures ensures the uniformity and consistency in the results and quality of data reported that the commenters agree is important for comparability of emissions.

We also used the Cement CO_2 Protocol as a model for revising our equations in 40 CFR 98.83 to account for non-carbonate sources of calcium and magnesium that may be present in the kiln feed.

Monitoring and QA/QC Requirements

Comment: One commenter expressed concern that 40 CFR 98.84(e) and (f) seem to require continuous, direct weight measurement of CKD discarded and raw materials used, by category of material. The commenter stated that most cement plants do not have that capability, and that the proposed rule does not clearly state whether installation of additional measurement equipment will be required if not already installed.

One industry representative further recommended that EPA add truck weight scales as an acceptable option for raw material weight measurement to address certain limited cases in which this method may be more appropriate to use. In addition, the commenter recommended that EPA allow CKD samples to be taken either as CKD exits the kiln or from bulk storage.

Response: We revised the text in 40 CFR 98.84(e) and (f) to more clearly state that CKD quantities are required to be measured on a quarterly basis and raw material quantities are required to be measured on a monthly basis. Furthermore, the Proposed Rule was never intended to require installation of new monitoring equipment for this purpose. We agree with the commenter that continuous, direct weight measurement of these materials and installation of additional measurement equipment would be unnecessary. The proposed rule clearly stated that the quantity of CKD produced and raw materials consumed must be determined using the same plant instruments that the cement plant currently uses for accounting purposes. Moreover, because the quantities of raw materials and CKD do not greatly impact the CO_2 calculation, we added further clarification to this section to allow cement plants to use potentially less accurate, but commonly used, methods of measurement, such as truck weigh scales, to determine quantities of CKD and raw materials. We also added clarification to 40 CFR 98.84 to allow facilities to collect CKD samples either as CKD exits the kiln or from bulk storage.

Data Reporting Requirements

Comment: Two commenters asserted that EPA needs to provide clarifying language within 40 CFR part 98, subpart H (Cement Production) to define which requirements apply to facilities using CEMS to monitor CO_2 emissions. One commenter noted that the Proposed Rule, as written, appears to require cement plants using CEMS to collect maintain, and report process data related to calculating CO_2 process emissions for kilns pursuant to proposed 40 CFR 98.84 through 98.87. This commenter claimed that requiring plants to collect and report such process data are redundant if the facility is continuously monitoring CO_2 emissions. Another commenter recommended that EPA state within 40 CFR part 98, subpart H (Cement Production) that all of the requirements detailed in the subpart do not apply to cement kilns using Tier 4 (CEMS) method.

Response: We agree with the comment that reporters who are using CEMS to monitor CO_2 do not need to collect, report, and maintain all of the process data required in proposed 40 CFR 98.84 through 98.87. However, we determined that some of the process data are necessary for emissions verification purposes, and therefore, plants using CEMS are not completely excluded from the requirements in 40 CFR part 98, subpart H (Cement Production). We added clarifying language throughout the Subpart to clearly state which requirements will apply to facilities that use CEMS to measure CO_2 emissions. Specifically, we created separate lists of reporting requirements and recordkeeping requirements for cement plants using CEMS.

Comment: One commenter noted that the data reporting requirements for cement plants, set forth in proposed 40 CFR 98.86, are expressed in different terms that those used for the specified procedures for calculating emissions. For example, the commenter stated that it is unclear what emission sources go into the ''site-specific emission factor (metric tons CO_2/metric ton clinker produced)'' required to be reported under proposed 40 CFR 98.86(h), and how that factor would be calculated.

Response: We agree with the commenter that there were inconsistencies between 40 CFR 98.83 and 98.86. We updated reporting requirements in 40 CFR 98.86 to be consistent with the terms used in the emission calculation procedures in 40 CFR 98.83 and provide clarification in 40 CFR 98.83 for terms if needed. As a result, some calculations that are performed on a kiln-specific basis, such as CO_2 emission factors, will be required to be reported on a kiln-specific basis in 40 CFR 98.86. Also see the Section II.N of this preamble for the response to comments on the emissions verification approach.

I. Electronics Manufacturing

At this time EPA is not going final with the electronics manufacturing subpart. As we consider next steps, we will be reviewing the public comments and other relevant information.

The Agency received a number of lengthy, detailed comments regarding the electronics manufacturing subpart. Commenters generally opposed the proposed reporting requirements and stated the proposal required excessive detail. For example, commenters asserted that they currently do not collect the data required to report using an IPCC Tier 3 approach and that to collect such data would entail significant burden and capital costs. In most cases, commenters provided alternative approaches to each of the reporting requirements proposed by EPA.

Commenters also requested clarification from EPA on a number of the proposed reporting provisions.

Based on careful review of comments received on the proposal preamble, rule, and technical support documents (TSDs) under proposed 40 CFR part 98, subpart I, EPA will perform additional analysis and evaluate a range of data collection procedures and methodologies. EPA's goal is to optimize methods of data collection to ensure data accuracy while considering industry burden.

J. Ethanol Production

At this time, EPA is not finalizing the Ethanol Production Subpart. The sources of GHG emissions at ethanol production facilities that were to be reported under the proposed rule were stationary fuel combustion, onsite landfills, and onsite wastewater treatment. EPA has decided not to finalize the portion of 40 CFR part 98, subpart HH (Landfills) that addresses industrial landfills nor 40 CFR part 98, subpart II (Wastewater Treatment). Stationary fuel combustion sources at ethanol production facilities are subject to the requirements of 40 CFR part 98, subpart C if general stationary fuel combustion emissions exceed the 25,000 metric tons CO_2e threshold.

As EPA considers next steps, we will be reviewing the public comments and other relevant information. Based on careful review of comments received on the proposal preamble, rule and TSDs under proposed 40 CFR part 98, subparts J, HH, and II, EPA will perform additional analysis and consider alternatives to data collection procedures and methodologies contained in those subparts.

K. Ferroalloy Production

1. Summary of the Final Rule

Source Category Definition. The ferroalloy production source category consists of facilities that use pyrometallurgical techniques to produce any of the following metals: ferrochromium, ferromanganese, ferromolybdenum, ferronickel, ferrosilicon, ferrotitanium, ferrotungsten, ferrovanadium, silicomanganese, or silicon metal.

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. For ferroalloy production, report the following emissions.

- Annual process CO_2 emissions from each EAF used for production of any ferroalloy listed in the source category definition.
- Annual process CH_4 emissions for those EAFs used for the production of silicon metal, ferrosilicon 65 percent, ferrosilicon 75 percent, or ferrosilicon 90 percent.
- CO_2, N_2O, and CH_4 emissions from each stationary combustion unit on site under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).
- In addition, report emissions from any other source categories for which calculation methodologies are specified in the rule, as applicable.

GHG Emissions Calculation and Monitoring. To calculate process CO_2 emissions from EAFs, reporters can use one of two methods, as appropriate:

- Most reporters can elect to calculate and report process CO_2 emissions from each EAF by either (1) installing and operating a CEMS and following the Tier 4 methodology (in 40 CFR part 98, subpart C) or (2) using the carbon mass balance calculation procedure specified in the rule and summarized below.
- However, if CO_2 process emissions from an EAF are emitted through the same stack as CO_2 emissions from a combustion unit or process equipment that uses a CEMS and follows Tier 4 methodology to report CO_2 emissions, then the CEMS must be used to measure and report combined emissions from that stack, instead of using the carbon mass balance calculation procedure described below.
- If using the carbon mass balance procedure, perform a once per year calculation using equations in the rule and:

—Recorded monthly production data, and
—The average carbon content for each EAF input and output material determined by either using material supplier information or by annual analysis of representative samples of the material.

- For those EAF's for which the reporter must report annual CH_4 emissions, annual ferroalloy production data are used with an applicable emissions factor provided in the rule.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart K.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart K.

2. Summary of Major Changes Since Proposal

The major changes to the rule since proposal for ferroalloy production facilities were revisions to the carbon mass balance calculation procedure for calculating process CO_2 emissions from EAFs. These changes reduce the reporting burden and are consistent with revisions made to other similar industries. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart K: Ferroalloy Production.''

• Frequency of performing the carbon mass balance calculations was revised to be required on an annual basis instead of the proposed monthly basis.

• Frequency of material carbon content sampling and analysis of each EAF input and output material used for the material balance was revised to be performed by annual analysis of representative samples of the material instead of the proposed monthly basis.

• Materials contributing less than one percent of the total carbon into or out of the EAF do not need to be included carbon mass balance calculations.

• 40 CFR 98.116 and 98.117 were reorganized and updated to improve the emissions verification process. Some data elements were moved from 40 CFR 98.117 to 40 CFR 98.116, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.173 were added to 40 CFR 98.116 for clarity. See Section II.N of this preamble for the response to comments on the emissions verification approach.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Other comments on ferroalloy production were received covering various topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart K: Ferroalloy Production.''

Comment: One comment was received on the proposed rule specific to ferroalloy production facilities. The commenter requested that EPA allow ferroalloy production facilities to use alternative methods for determining EAF process CO_2 emissions other than those proposed, and specifically a protocol for silicon metal production facilities developed for use by the Chicago Climate Exchange. This smelting protocol was developed a protocol for calculating the CO_2 emissions from based on the World Resources Institute (WRI) aluminum smelting protocol.

Response: We reviewed the WRI aluminum smelting protocol, which was publicly available and we tried to obtain a copy of the specific protocol that the commenter mentions to fully evaluate whether it is an appropriate alternative. However, we never received it in the long run. The commenter did not provide additional or more specific recommendations beyond the reference to improve or revise the proposed methodology. At this time, given insufficient information, we have decided not to include additional alternative methods in the final rule for ferroalloy production facilities. As we stated at proposal, the selected methodology was based on review of several existing methodologies used by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Canadian Mandatory Greenhouse Gas Reporting Program, the Australian National Greenhouse Gas Reporting Program, and EU Emissions Trading System.

However, we have revised the frequency of sampling and analysis of carbon contents for carbon containing input and output materials monthly to annual consistent with revisions made in response to comments for similar production processes (e.g. emissions from metal production). These revisions reduce the reporting burden for ferroalloy production facilities. We understand that the carbon content of material inputs and outputs does not vary widely at a given facility for the significant process inputs that contain carbon, and we continue to account for variations due to changes in production rate, which is likely a more significant source of variability. The response to the comment can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart K: Ferroalloy Production.''

L. Fluorinated GHG Production

At this time EPA is not going final with the subpart for emissions from fluorinated GHG production. As we consider next steps, we will be reviewing the public comments and other relevant information.

The Agency received a number of lengthy, detailed comments regarding the fluorinated GHG production subpart. Commenters generally opposed the proposed reporting requirements. Several commenters stated that facilities could not meet the proposed accuracy, precision, and frequency requirements using existing equipment and practices. These commenters stated that they would need to expend significant funds (millions of dollars in some cases) and time to install Coriolis flowmeters in multiple streams and to implement daily sampling protocols to analyze the contents of these streams. Some commenters stated that even after such equipment was installed, the proposed mass-balance approach was likely to be inaccurate, particularly for batch processes. In most cases, commenters provided alternative approaches, such as emission-factor based approaches, to the proposed mass-balance approach.

Based on careful review of comments received on the proposal preamble, rule, and TSDs under proposed 40 CFR part 98, subpart L, EPA will perform additional analysis and evaluate a range of data collection procedures and methodologies. EPA's goal is to optimize methods of data collection to ensure data accuracy while considering industry burden.

M. Food Processing

At this time, EPA is not going final with the Food Processing Subpart. The sources of GHG emissions at food processing facilities that were to be reported under the proposed rule were stationary fuel combustion, onsite landfills, and onsite wastewater treatment. EPA has decided not to finalize the portion of 40 CFR part 98, subpart HH (Landfills) that addresses industrial landfills nor 40 CFR part 98, subpart II (Wastewater Treatment). Note, however, that Stationary fuel combustion sources at food processing facilities are subject to the requirements of 40 CFR part 98, subpart C if general stationary fuel combustion emissions exceed the 25,000 metric ton CO_2e threshold. As EPA considers next steps, we will be reviewing the public comments and other relevant information.

Based on careful review of comments received on the proposal preamble, rule and TSDs under proposed 40 CFR part 98, subparts M, HH, and II, EPA will perform additional analysis and consider alternatives to data collection procedures and methodologies contained in those subparts.

N. Glass Production

1. Summary of the Final Rule

Source Category Definition. The glass production source category consists of facilities that manufacture glass (including flat, container, pressed, or blown glass) or wool fiberglass using one or more continuous glass melting furnaces. Experimental furnaces and research and development process units are excluded.

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. For glass production facilities, report the following emissions:

- CO_2 process emissions from each continuous glass melting furnace.
- CO_2 combustion emissions from each continuous glass melting furnace,
- CH_4 and N_2O emissions from fuel combustion at each continuous glass melting furnace under 40 CFR part 98, subpart C (General Stationary Combustion Sources) using the methodologies in subpart C.
- CO_2, CH_4, and N_2O emissions and from each onsite stationary fuel combustion unit other than continuous glass melting furnaces under 40 CFR part 98, subpart C (General Stationary Combustion Sources).

In addition, report GHG emissions for any other source categories at the facility for which calculation methods are provided in other subparts of the rule, as applicable.

GHG Emissions Calculation and Monitoring. For CO_2 process emissions from glass melting furnaces, reporters must use one of two methods, as appropriate:

- For glass melting furnaces with certain types of CEMS in place, reporters must use the CEMS and follow the Tier 4 methodology (in 40 CFR part 98, subpart C) to measure and report under the glass production subpart (40 CFR part 98, subpart N) combined process and combustion CO_2 emissions.
- For other glass melting furnaces, the reporter can elect to either (1) install and operate a CEMS and follow the Tier 4 methodology to measure and report combined process and combustion CO_2 emissions or (2) calculate process CO_2 emissions for each furnace using an emission factor and process data. If using approach (2), multiply a default emission factor appropriate for the carbonate raw material by:

—The annual mass of carbonate-based raw material charged to the furnace (required to be measured); and

—The mass-fraction of carbonate in the raw material (based on data supplied by the raw material supplier and verified by an annual measurement).

—Under approach (2), report process CO_2 emissions from each glass melting furnace under 40 CFR part 98, subpart N (Glass Production), and report combustion CO_2 emissions from each glass furnace under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart N.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart N.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart N: Glass Production.''

- The definition of the term ''glass produced'' was added to the definitions in 40 CFR part 98, subpart A.
- 40 CFR 98.146 was reorganized and updated to improve the emissions verification process. Some data elements were moved from 40 CFR 98.147 to 40 CFR 98.146, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.143 were added to 40 CFR 98.146 for clarity.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments on glass production were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart N: Glass Production.''

Definition of Source Category

Comment: One commenter stated that EPA should exempt from the rule all fiber glass and rock and slag wool insulation facilities within the glass production source category because glass production facilities subject to the proposed rule are a miniscule portion of the total national emissions of CO_2e, and amount to less than 0.1 percent of total GHG emissions in the U.S. and the subset of fiber glass and rock and slag wool insulation facilities is an even smaller portion. The commenter stated that there is virtually no benefit to having the glass production source category subject to the proposed rule, and any benefit is outweighed by the burden imposed on these facilities. The commenter also pointed out the importance of the fiber glass and rock and slag wool insulation industry's products in meeting the nation's energy needs and reducing GHG emissions. Exempting the industry from the proposed rule's reporting requirements will help the industry focus more of its scarce resources on producing insulation.

Response: We recognize that the glass manufacturing industry is comprised of a wide range of facilities, many of which are small in size and have relatively low levels of emissions. However, the data we have collected on the industry indicate that there are several large glass manufacturing plants with significant GHG emissions. These plants include some that produce glass fiber, flat glass, and container glass, as well as other types of pressed and blown glass products. As a result, we do not agree with the commenter that fiber glass and other types of insulation facilities should be exempt from reporting. However, we tried to reduce the burden on the glass manufacturing industry by incorporating into the proposed rule a 25,000 metric ton CO_2e threshold, which should preclude small facilities from having to report GHGs. This threshold remains in the final rule. Thus, any small fiber glass and rock and slag wool insulation facilities with low GHG emissions will fall under the threshold and will be exempt from reporting. To further minimize the burden on the industry, we have tried to limit recordkeeping and reporting requirements to the types of data that glass production facilities already collect as part of normal business operations.

Commenters may also be interested in reviewing Section II.H of this preamble for the response on provisions to cease reporting. The final rule contains provisions to cease reporting if annual reports demonstrate emissions less than specified levels for multiple years.

Selection of Threshold

Comment: One commenter remarked that EPA should raise the threshold for reporting for fiberglass and rock and slag wool insulation entities. Doing so would reduce the number of entities reporting with only a minimal impact on the amount of emissions covered. The commenter stated that EPA's analysis did not address reasonable alternative thresholds between 25,000 and 100,000 metric tons.

Response: When evaluating potential thresholds for reporting GHG emissions, we considered several thresholds between 1,000 and 100,000 metric tons CO_2e. We selected the 25,000 metric tons CO_2e threshold for reporting GHG emissions in order to achieve a balance between quantifying the majority of the emissions and minimizing the number of facilities impacted. For example, at a 1,000 metric tons CO_2e threshold, 98 percent of emissions would be covered, with about 58 percent of facilities being required to report. Compared to the 100,000 metric tons CO_2e threshold, the proposed 25,000 metric tons CO_2e threshold achieves reporting of 11 times more emissions while requiring less than 15 percent of the facilities to report. Compared to the 10,000 metric tons CO_2e threshold, the 25,000 metric tons CO_2e threshold captures more than half of those emissions, but only requires a third of the facilities in the industry to report. This threshold offers significant coverage of the GHG emissions while impacting a relatively small portion of the industry. Although a threshold of 50,000 metric tons CO_2e would greatly reduce the number of facilities reporting, it would capture less than 20 percent of total emissions for the industry. We believe the proposed threshold of 25,000 metric tons CO_2e represents the best option for ensuring that the majority of emissions are reported without imposing an unreasonable burden on the industry.

Section II.E of this preamble contains a general discussion of the selection of the 25,000 metric tons CO_2e threshold.

Method for Calculating GHG Emissions

Comment: One commenter fully supports EPA's proposed rule for measuring, calculating, monitoring, and reporting emissions from the glass melting process. They agree that 40 CFR part 98, subpart N represents a good balance between site reporting burden, cost, and data accuracy and consistency. Specifically, the commenter supports using raw-material emissions factors and usage rates, as proposed, to calculate emissions from glass production in lieu of requiring installing CEMs on sources that another regulation does not currently require to be installed.

Response: We acknowledge this support for the proposal and appreciate these comments. We have retained the proposed calculation methodology in the final rule.

Data Reporting Requirements

Comment: One commenter stated that, at various places in the preamble and proposed rule, EPA uses the phrase "glass produced," but has not defined this phrase in the rule. The commenter noted that the phrase could be interpreted to mean either glass melted or glass product produced. The commenter assumed that the phrase refers to the amount of glass melted, but requested clarification.

Response: We agree that the term glass produced is subject to interpretation. We have added a definition of the term to 40 CFR part 98, subpart A of the final rule. "Glass produced" means the weight of glass exiting a glass melting furnace.

Comment: One commenter remarked that some of the information that would have to be reported under the proposed rule, such as annual quantity of glass produced, is considered to be company confidential and could be used by competitors to back-calculate product formulas. The commenter requested that EPA remove these reporting requirements from the rule and instead, require that the data be retained by the facility and made available for review by EPA. Should EPA require the reporting of all of this information in the final rule, the commenter requests that EPA explicitly state in the final rule and confirm in the preamble to the final rule that all information provided under 40 CFR part 98, subpart N, other than the annual process emissions of CO_2, is considered confidential information and would not be considered "emission data" under this reporting rule. The commenter requests that a new paragraph (e) be added to 40 CFR 98.146 that reads: "No information required to be reported by this section, other than the information required by 40 CFR 98.146(a), is considered to be emission data under 40 CFR 2.301(a)(2)(i) and (ii)."

Response: We acknowledge the commenter's concerns. However, the quantity of glass produced is an important variable for EPA to verify whether reported emissions are within a reasonable range and therefore is a required reporting parameter under 40 CFR part 98, subpart N.

We have reviewed CBI comments received across the rule (both general and subpart-specific comments) and our response is discussed in Section II.R of this preamble and in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues."

O. HCFC–22 Production and HFC–23 Destruction

1. Summary of the Final Rule

Source Category Definition. This source category consists of:

• Processes that produce HCFC–22 (chlorodifluoromethane or $CHClF_2$) using chloroform and hydrogen fluoride.

• HFC–23 destruction processes located at HCFC–22 production facilities.

• HFC–23 destruction processes that destroy more than 2.14 metric tons of HFC–23 per year and that are not located at HCFC–22 production facilities.

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. For facilities that produce HCFC–22 or that destroy HFC–23, report the following emissions:

• HFC–23 emissions from all HCFC–22 production processes at the facility.

• HFC–23 emissions from each destruction process.

In addition, report GHG emissions for other source categories at the facility for which calculation methods are provided in the rule, as applicable. For example, report CO_2, N_2O, and CH_4 emissions from each stationary combustion unit on site by following the requirements of 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

GHG Emissions Calculation and Monitoring. Reporters must calculate HFC–23 emissions as follows:

• For HCFC–22 production processes that do not use a thermal oxidizer or that have a thermal oxidizer that is not connected to the production equipment, calculate annual HFC–23 emissions at the facility level using a mass balance equation and the following information: annual HFC–23 generated, the annual HFC–23 sent off site for sale, the annual HFC–23 sent off site for destruction, the annual increase in the HFC–23 inventory, and the annual HFC–23 destroyed on site (calculated by multiplying the mass of HFC–23 fed to the destruction device by the destruction efficiency).

• For HCFC–22 production processes with a thermal oxidizer that is connected to the production equipment, calculate annual HFC–23 emissions at the facility level by summing the following emissions:

—Annual HFC–23 emissions from equipment leaks (calculated using default emission factors and the measured number of leaks in valves, pump seals, compressor seals, pressure relief valves, connectors, and open-ended lines).

—Annual HFC–23 emissions from process vents (calculated for each vent using the HFC–23 emission rate from the most recent emission test and the ratio of the actual production rate and the production rate during the emission test).

—Annual HFC–23 from the thermal oxidizer (calculated by subtracting the amount of HFC–23 destroyed by the destruction device from the measured mass of HFC–23 fed to the destruction device).

• For other HFC–23 destruction processes, calculate HFC–23 emissions based on the mass of HFC–23 fed to the destruction device and the destruction efficiency.

• For the destruction efficiency, conduct a performance test or use the destruction efficiency determined during a previous performance test. To confirm the destruction efficiency, measure the fluorinated GHG concentration at the outlet to the destruction device annually.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart O.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart O.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart O: HCFC–22 Production and HFC–23 Destruction.''

• The minimum required frequency of mass flow and concentration measurements has been decreased from daily to weekly.

• The required frequency of emissions tests at process vents has been decreased to once every five years. A test is also required after a significant change is made to the process.

• The required annual measurements at the outlet of the thermal oxidizer now omit measurements of mass flow. Three samples are required to be taken; the average of these is compared to the concentration at the outlet of the oxidizer that was measured during the initial performance test that established the destruction efficiency.

• A term has been added to the mass-balance equation for HCFC–22 production facilities that do not have a thermal oxidizer that is directly connected to the HCFC–22 production equipment. This term accounts for increases in the inventory of stored HFC–23 that can occur during the year.

• EPA has added an additional method for estimating missing mass flow data in the event that a secondary mass measurement for that stream is not available.

• The option for reporters to develop their own methods for estimating missing data if they believe that the prescribed method will over- or under-estimate the data has been removed.

• Some reporting requirements have been added to be consistent with the changes to the calculations and monitoring sections and to permit verification of emissions calculations.

EPA decreased the minimum frequency of gas flow and concentration measurements from daily to weekly because EPA's research indicates that HFC–23 concentrations are not likely to vary significantly over a one week period. This change also makes the required measurement frequency more consistent with current industry practice.

As noted above, EPA removed the option for reporters to develop their own methods for estimating missing data if they believe that the prescribed method will over- or underestimate the data. EPA removed this option for two reasons. First, the proposed provision lacked clear guidance on when alternative methods should be used (e.g., on the size of an underestimate that would justify use of an alternative method) and on how they should be developed. Second, the proposed provision was redundant with the new provision that permits reporters to estimate missing data using a related parameter and the historical relationship between the related parameter and the missing parameter. This new option provides reporters with flexibility in substituting for missing data in the event that a secondary mass measurement is not available, but sets out general guidance on how to select the substitute data.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A number of comments on HCFC–22 production and HFC–23 destruction were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart O: HCFC–22 Production and HFC–23 Destruction.''

Monitoring and QA/QC Requirements

Comment: EPA received a comment that the requirement to annually conduct emissions tests at process vents is overly burdensome and unnecessary because it is unlikely that the emissions rate would deviate from an initial process vent test unless there were a significant change in the process. This commenter argued that testing should be required at least every five years or after a significant change in the process.

Response: In response to this comment, EPA has reduced the required frequency of emissions tests at process vents to once every five years, or after a significant change to the process. EPA has also clarified that the requirement applies only to HCFC–22 production facilities that use a thermal oxidizer connected to the HCFC–22 production equipment. These are the only facilities that use process vent emission estimates in their calculation of facility-wide HFC–23 emissions.

EPA is decreasing the frequency of emissions tests at process vents for two reasons. First, EPA agrees with the commenter that, in the absence of a significant process change, the process vent emission rate is not likely to vary much (in percentage terms) from year to year. Second, although small variations in the emission rate could still lead to significant absolute errors for facilities with large process vent emissions, the facilities that are required to test their process vent emissions are likely to have small process vent emissions (because they use thermal oxidizers connected to the production equipment). (Facilities that do not use thermal oxidizers connected to the equipment would be expected to have larger process vent emissions, but they are required to use a mass-balance approach to calculate emissions rather than summing emissions across process vents, equipment leaks, and thermal oxidizers.) Together, these considerations lead to the conclusion that testing process vent emissions every five years should sufficiently minimize errors in the overall HFC–23 emission calculations of the facilities affected by the testing requirement.

Comment: EPA should add a term to Equation O–4 (the mass-balance equation for HCFC–22 production facilities that do not have a thermal oxidizer that is directly connected to the HCFC–22 production equipment) to account for increases in the inventory of stored HFC–23 that can occur during the year.

Response: EPA added a term to Equation O–4 for increases in the inventory of stored HFC–23. EPA agrees that the equation should account for changes in the inventory of HFC–23 that is stored on site. It is important to track all reservoirs of HFC–23 at the facility; mass-balance approaches used to track emissions from other sources (e.g., from electrical equipment) frequently include terms to account for the increase in inventory.

Definition of Source Category

Comment: EPA received a comment that the measurement of HFC–23 emissions from HCFC–22 production should be moved to Subpart L, which covers the reporting of fluorinated GHG production.

Response: EPA proposed provisions for facilities producing fluorinated gases in three separate subparts: 40 CFR part 98, Subpart L, Subpart O, and Subpart OO. Although there are many similarities across the chemicals and processes covered by the three subparts, the subparts were deliberately tailored to different sources and types of emissions. Subpart L was intended to address emissions of fluorinated GHGs from fluorinated GHG production. 40 CFR part 98, subpart O was intended to address HFC–23 generation and emissions from HCFC–22 production. 40 CFR part 98, subpart OO was intended to address flows affecting the U.S. industrial gas supply, including production, transformation, and destruction.

EPA determined that 40 CFR part 98, subpart O was necessary because HCFC–22 production and HFC–23 destruction facilities differ from other fluorinated gas production facilities in two key respects. First, the primary fluorinated GHG that they generate (HFC–23) is made as a byproduct to the production of a substance that is not defined as a fluorinated GHG (HCFC–22). Second, due to the very high GWP of HFC–23, each HCFC–22 facility generates very large quantities of CO_2-equivalent. For the second reason, EPA has worked with HCFC–22 producers for over ten years to understand and reduce HFC–23 emissions. The requirements for HCFC–22 producers are therefore based on a close knowledge of their production processes and methods for accounting for emissions. These methods are also comprehensive (e.g., accounting for emissions from equipment leaks and losses during transport of HFC–23 that is shipped off-site for destruction). These requirements may not be appropriate for other fluorinated gas producers, and, at the same time, the requirements for fluorinated gas producers may not be appropriate for HCFC–22 producers.

P. Hydrogen Production

1. Summary of the Final Rule

Source Category Definition. The merchant hydrogen production source consists of process units that produce hydrogen by reforming, gasification, or other transformation of feedstock and transfer the hydrogen produced off site. Hydrogen production facilities located at petroleum refineries or other large facilities are included in this source category only if they are not owned by or under the direct control of the refinery owner. Otherwise, they are considered to be a captive hydrogen production source that reports emissions under the subpart applicable to the larger facility, e.g., 40 CFR part 98, subpart Y (Petroleum Refineries).

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. For hydrogen production, report the following emissions:

- CO_2 process emissions from hydrogen production.
- CO_2, N_2O, and CH_4 emissions from each stationary combustion unit on site by following the requirements of 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).
- CO_2 collected and transferred off site under 40 CFR part 98, subpart PP (Suppliers of Carbon Dioxide).
- In addition, report GHG emissions for other source categories for which calculation methods are provided in the rule, as applicable.

GHG Emissions Calculation and Monitoring.

- To calculate and report process CO_2 emissions from hydrogen production, most reporters can elect to either (1) install and operate CEMS and follow the Tier 4 methodology (in 40 CFR part 98, subpart C) or (2) calculate process CO_2 emissions using equations in the 40 CFR part 98, subpart P and the following data:

—Measurements of monthly feedstocks and fuel consumed.

—Carbon content of the feedstock measured monthly.

—Molecular weight of the feedstock (gaseous fuels only).

- However, if process CO_2 emissions from hydrogen production are vented through the same stack as a combustion unit or process equipment that uses a CEMS to follow Tier 4 methodology to report CO_2 emissions, then the CEMS must be used to measure and report combined CO_2 emissions from that stack instead of the calculation procedure described in approach 2 above.

Monitoring and QA/QC Requirements. The methods for the initial calibration and annual recalibration of flow meters are defined in a prescriptive list of industry standard test methods incorporated by reference in the Tier 3 method in 40 CFR part 98, subpart C, while the methods for determining carbon content of fuels and feedstocks are defined in a prescriptive list of an assortment of industry standard test methods incorporated by reference.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart P.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart P.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ‘‘Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart P: Hydrogen Prodution.’’

- 40 CFR 98.160 was reworded to clarify the definition of reporting entity.
- 40 CFR 98.162 was revised to allow reporting of combined process and combustion CO_2, CH_4, and N_2O emissions.
- In 40 CFR 98.163(b), ‘‘feedstock’’ was changed to ‘‘fuel and feedstock’’.
- 40 CFR 98.164 was restructured to clarify between CEMS measurements and QA/QC and feedstock method measurements and QA/QC.
- 40 CFR 98.164 was reworded to allow the characterization of feedstocks to be conducted by either the consumer or the supplier, to allow standard gaseous hydrocarbon fuels of commerce to be characterized annually, and to allow liquid and solid hydrocarbon fuels of commerce to be characterized

upon delivery if delivered by bulk transport.

- The recalibration requirements in 40 CFR 98.164 were changed to reduce economic impact.
- The list of standards incorporated by reference in 40 CFR 98.164 was broadened.
- The missing data procedures in 40 CFR 98.165 were revised to be consistent with 40 CFR 98.35(b).
- 40 CFR 98.166 and 98.167 were restructured to distinguish between CEMS recordkeeping and feedstock method recordkeeping.
- 40 CFR 98.166 was reorganized and updated to improve the emissions verification process. Some data elements were moved from 40 CFR 98.167 to 40 CFR 98.166, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.163 were added to 40 CFR 98.166 for clarity.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on hydrogen production were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart P: Hydrogen Production.''

Definition of Source Category

Comment: Multiple commenters pointed out the lack of clarity regarding the definition of the reporting entity, and suggested defining the entity holding the air permit for an affected facility as the reporting entity. For example, ''If the owner/operator of the facility is the holder of the air permit for an affected facility, then the operator should be responsible for reporting GHG emissions. If not, then EPA should clarify the responsibility for reporting.''

Response: EPA reviewed this complex issue. First, a facility is defined in 40 CFR 98.6: ''*Facility* means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas.'' Therefore, any hydrogen production process unit that is not part of a larger facility covered by another subpart of this rule is a merchant hydrogen production facility which reports emissions under 40 CFR part 98, subpart P. On the other hand, a hydrogen production process unit that is part of a larger facility covered by another subpart of this rule is a captive hydrogen production facility that does not report emissions under 40 CFR part 98, subpart P. Their emissions, including those emissions from the captive hydrogen production facility, are reported under the subpart applicable to the larger facility. Second, in answer to the question, ''Do I need to report?'', 40 CFR 98.2 states that the rule applies to a facility that contains any source category listed in 40 CFR 98.2(a)(2) (which includes hydrogen production) and that emits 25,000 metric tons CO_2e or more per year in combined emissions from stationary fuel combustion units, miscellaneous uses of carbonates, and all source categories listed in 40 CFR 98.2(a)(2). EPA has concluded that the rule explains this clearly in 40 CFR 98.2 and 98.6, and that it is not necessary to change the rule. To add clarity, however, EPA has revised 40 CFR 98.160(c) as follows: ''This source category includes merchant hydrogen production facilities located within a petroleum refinery if they are not owned by, or under the direct control of, the refinery owner and operator.''

GHGs To Report

Comment: Multiple commenters requested clarification on the CO_2 emission reporting obligation as combined ''process'' and ''combustion'' CO_2 emissions, regardless of the calculation method employed. If separate, discrete reporting of such emissions is actually required, commenters asked EPA to provide explicit protection for this information which they stated was very critical CBI.

Response: In response to these multiple commenters, EPA has clarified the rule in 40 CFR 98.162 to provide operators the option of providing combined process and combustion CO_2 emissions for each hydrogen production process unit whether or not it meets the conditions in 40 CFR 98.33(b)(4)(ii) and (iii) for CEMs. Under 40 CFR 98.166, facilities must report additional parameters for emissions verification.

See Sections II.I and II.N of this preamble for responses to the comments received on the general content of the annual GHG report and the emissions verification approach, respectively. EPA reviewed CBI comments received across the rule (both general and subpart-specific comments) and our response is discussed in Section II.R of this preamble and in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues.''

Method for Calculating GHG Emissions

Comment: Multiple commenters pointed out the need for a calculation method to account for feedstock carbon that does not exit the hydrogen production facility as CO_2, but rather in the form of other products or co-products that contain carbon (such as synthesis gas, CO, CH_4). Many argued in favor of correcting equations P–1, P–2 and P–3 to account for feedstock carbon that does not exit the hydrogen production facility as CO_2, but rather as products (such as synthesis gas, CO, CH_4) that are manufactured which contain carbon.

Response: EPA generally concurs with the need to account for ''carbon other than CO_2'' that exits the facility. EPA considered several options for reporting such carbon and chose to have facilities report CO_2 and ''carbon other than CO_2'' as separate data reporting elements in 40 CFR 98.166 rather than including this carbon in equations P–1, P–2, and P–3. As a result, EPA has added data reporting elements under 40 CFR 98.166 for (1) quarterly quantity of CO_2 collected and transferred off site in either gas, liquid, or solid forms (metric tons), following the requirements of 40 CFR part 98, subpart PP of this part, and (2) annual quantity of carbon other than CO_2 collected and transferred off site in either gas, liquid, or solid forms (metric tons).

Monitoring and QA/QC Requirements

Comment: Multiple commenters recommended that EPA should allow the characterization of feedstocks (sampling and analysis) to be conducted by either the feedstock consumer (the regulated source) or the feedstock supplier. They state that the characterization of standard fuels of commerce used as hydrogen production feedstocks, such as natural gas, should not be required since default values will yield a sufficiently accurate emission estimate. Commenters recommend that characterization of such standard fuels of commerce used as feedstocks be optional, at the source's discretion.

Response: EPA concurs with this comment, since feedstock suppliers regularly monitor the carbon content of their fuels and also, the carbon content of standard fuels of commerce are quite consistent month to month. EPA has revised this section to allow the characterization of feedstocks to be conducted by either the consumer or the supplier, to allow standard gaseous hydrocarbon fuels of commerce to be characterized annually, and allow liquid and solid hydrocarbon fuels of commerce to be characterized upon delivery if delivered by bulk transport (e.g., by truck or rail). Other non-standard gaseous fuels and feedstocks must still be subjected to weekly sampling and analysis to determine the carbon content and molecular weight.

Comment: Commenters recommended that EPA limit the requirement for sampling non-gaseous fuels to new deliveries rather than monthly in order to pinpoint the onset of fuel parameter variations.

Response: EPA concurs that the carbon content of a liquid or solid hydrocarbon fuel delivered in bulk will remain constant as the stock on hand from the delivery is consumed, and therefore periodic testing during the interim is not needed. EPA has revised this section to allow the characterization of feedstocks to be conducted by either the consumer or the supplier, to allow standard gaseous hydrocarbon fuels of commerce to be characterized annually, and allow liquid and solid hydrocarbon fuels of commerce to be characterized upon delivery if delivered by bulk transport (e.g., by truck or rail). On the other hand, other non-standard gaseous fuels and feedstocks must still be subjected to weekly sampling and analysis to determine the carbon content and molecular weight since their carbon content can vary significantly from week to week.

Comment: Multiple commenters recommended that EPA should include provisions for an extension of the required meter/monitor calibration deadline (as well as the initial calibration, if appropriate) when the calibration would require removing the process line from service. They recommend that the calibration requirement be extended to the next scheduled maintenance shutdown for the impacted unit/process.

Response: EPA concurs that requiring the facility to remove the process line from service represents an undue hardship and has therefore revised 40 CFR part 98, subpart P to refer to the less stringent monitoring and QA/QC requirements for the Tier 3 methodology included in 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

Comment: One commenter suggested adding ISO 5167–1 through ISO 5167–4 (Measurement of Fluid Flow by Means of Pressure Differential Devices) to list of standards incorporated by reference.

Response: EPA agrees ISO 5167–1 through ISO 5167–4 are suitable calibration standards and would be good additions to the list of standards. However, given that the issues covered by these standards (Venturi and orifice plate differential pressure flow meters) are covered by two American Society of Mechanical Engineers (ASME) standards, one ASHRAE standard, and one AGA report which are already included in 40 CFR 98.164, EPA has not explicitly added these references to the list of standards incorporated by reference.

Procedures for Missing Data

Comment: Multiple commenters recommended that the data substitution method for missing feedstock supply rate data should be changed to be consistent with 40 CFR 98.35(b)(2), allowing use of the ''best available estimate'', and that the data substitution method for missing feedstock carbon content data should be changed to be consistent with 40 CFR 98.35(b)(1), allowing use of the average before/after values.

Response: EPA concurs that the required level of accuracy for hydrogen production is similar to that required for stationary combustion, and that the less stringent ''best available estimate'' approach is appropriate for hydrogen production. Therefore, EPA has changed 40 CFR 98.165 to follow the data substitution method for missing fuel carbon content data prescribed in 40 CFR 98.35 and the data substitution method for missing fuel usage data prescribed in 40 CFR 98.35.

Data Reporting Requirements

Comment: Multiple commenters stated that annual feedstock consumption, annual hydrogen production, and feedstock carbon content are confidential business information (CBI) and should not be reported. The commenters asked that this information be maintained by the facility and be made available to the Agency upon request. One commenter further stated that if data must be reported, the reporting rules must provide explicit protection for this very critical confidential business information.

Response: Feedstock consumption and feedstock carbon content are parameters used to calculate emissions. Since annual CO_2 emissions are calculated from the sum of the products of monthly feedstock consumption multiplied by the monthly average carbon content of the feedstock, all of these parameters are required for emissions data verification purposes. Annual hydrogen production is an additional parameter which is necessary for EPA to effectively verify emissions, since the ratio of carbon emissions to hydrogen production is relatively consistent for each hydrogen production facility. See Section II.N of this preamble for information on emissions verification. EPA reviewed CBI comments received across the rule (both general and subpart-specific comments) and our response is discussed in Section II.R of this preamble and in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues.''

Q. Iron and Steel Production

1. Summary of the Final Rule

Source Category Definition. The iron and steel production source category consists of facilities with any of the following processes:

- Taconite iron ore processing.
- Integrated iron and steel manufacturing.
- Cokemaking not co-located with an integrated iron and steel manufacturing process.
- EAF steelmaking not co-located with an integrated iron and steel manufacturing process.

Integrated iron and steel manufacturing means the production of steel from iron ore or iron ore pellets. At a minimum, an integrated iron and steel manufacturing process has a basic oxygen furnace for refining molten iron into steel. Each cokemaking process and EAF process located at a facility with an integrated iron and steel manufacturing process is part of the integrated iron and steel manufacturing facility.

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. Report the following emissions annually:

- CO_2, CH_4, and N_2O emissions from fuel combustion at each stationary combustion unit according to the requirements in 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources). Stationary combustion units include, but are not limited to, byproduct recovery coke oven battery combustion stacks, blast furnace stoves, boilers, process heaters, reheat furnaces, annealing furnaces, flame suppression, ladle reheaters, and any other miscellaneous combustion sources (except flares).
- CO_2 emissions from flares according to the requirements in 40 CFR part 98, subpart Y (Petroleum Refineries) and CH_4 and N_2O emissions from flares using the default emission factors for coke oven gas and blast furnace gas.
- CO_2 process emissions from each taconite indurating furnace, basic oxygen furnace, nonrecovery coke oven

battery combustion stack, coke pushing process, sinter process, EAF, argon-oxygen decarburization vessel, and direct reduction furnace.

In addition, report GHG emissions for any other source categories at the facility for which calculation methods are provided in other subparts of the rule, as applicable.

GHG Emissions Calculation and Monitoring. For CO_2 process emissions at each taconite indurating furnace, basic oxygen furnace, nonrecovery coke oven battery, sinter process, EAF, argon-oxygen decarburization vessel, and direct reduction furnace, reporters must calculate emissions using one of the following methods, as appropriate:

• Most reporters can elect to calculate and report process CO_2 emissions by either: (1) Installing and operating a CEMS and following the Tier 4 methodology (in 40 CFR part 98, subpart C) or (2) using one of the following two calculation procedures:

—Use a carbon balance method described in 40 CFR part 98, subpart Q to calculate the annual mass emissions rate of CO_2 for each process, based on the annual mass of inputs and outputs and an annual analysis of the respective weight fraction of carbon in each process input or output that contains carbon. Use separate procedures and equations for taconite indurating furnaces, basic oxygen process furnaces, nonrecovery coke oven batteries, sinter processes, EAFs, argon-oxygen decarburization vessels, and direct reduction furnaces, or

—Use a site-specific emission factor determined from a performance test that measures CO_2 emissions from all exhaust stacks and also measures either the feed rate of materials into the process or the production rate during the test for taconite indurating furnaces, basic oxygen process furnaces, nonrecovery coke oven batteries, sinter processes, EAFs, argon-oxygen decarburization vessels, and direct reduction furnaces.

• However, if process CO_2 emissions from a taconite indurating furnace, basic oxygen furnace, nonrecovery coke oven battery, sinter process, EAF, argon-oxygen decarburization vessel, and direct reduction furnace are emitted through the same stack as CO_2 emissions from a combustion unit or process equipment that uses a CEMS and follows the Tier 4 methodology to report CO_2 emissions, then the CEMS must be used to measure and report combined CO_2 emissions from that stack. In such cases, the reporter cannot use the other process CO_2 calculation approaches outlined above.

• For coke oven pushing, facilities must use a CO_2 emission factor provided in the rule.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart Q.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart Q.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart Q: Iron and Steel Production.''

The major changes made since proposal include:

• The carbon mass balance method was revised to require an annual analysis of all process inputs and outputs for carbon content rather than weekly sampling and monthly analysis.

• The site-specific emission factor method was revised to: (1) Require testing based on representative performance rather than at 90 percent of capacity, (2) sampling for a minimum of three hours or production cycles rather than nine, (3) conducting separate tests for each different process condition that is a part of normal operation if the change in CO_2 emissions at the different conditions is more than 20 percent, and (4) adding a provision to clarify testing requirements when the EAF and argon-oxygen decarburization vessel are ducted to the same control device and stack.

• To improve the emissions verification process, 40 CFR 98.176 was reorganized and updated. Some data elements were moved from 40 CFR 98.177 to 40 CFR 98.176, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.173 were added to 40 CFR 98.176 for clarity.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses related to the requirements for iron and steel processes. A large number of comments on iron and steel production were received covering numerous topics. Many of these comments were directed at the requirements for 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources), and responses to those comments are provided in Section III.C of this preamble. *Also see* the Section II.N of this preamble for the response to comments on the emissions verification approach. Responses to other significant comments received related to process emissions from iron and steel production can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart Q: Iron and Steel Production.''

Method for Calculating GHG Emissions

Comment: Several industry representatives and their three trade associations requested that EPA allow the use of a simplified facility-wide carbon balance approach developed by the American Iron and Steel Institute (AISI) to calculate CO_2 emissions from iron and steel production facilities. According to the commenters, the AISI methodology has recently been adapted to facility-wide reporting and is emerging as the preferred reporting protocol internationally. The commenters described the approach as based on determining the mass of carbon in the most significant carbon-containing inputs entering the plant and in the most significant carbon-containing outputs that leave as products or byproducts (excluding, for example, iron ore, scrap, steel). The difference between the mass of carbon entering the facility and leaving the facility is assumed to be converted to CO_2. The annual mass rates of significant inputs and outputs are determined from company records, and their carbon contents are based on typical or default values. The commenters noted that the AISI approach provides a single estimate of the combined total CO_2 emissions from all processes and combustion sources at the facility. The commenters claimed that the approach would provide a more accurate and complete accounting of facility-wide emissions at a much lower cost than that of the proposed EPA process-specific methods.

Response: As we explained at proposal (74 FR 16517), we considered the many domestic and international monitoring guidelines and protocols for process and combustion sources at iron and steel production facilities, including the AISI facility-wide approach. The vast majority of these guidelines and protocols are process-specific rather than facility-wide approaches (e.g., 2006 IPCC Guidelines, U.S. Inventory, the World Business Council for Sustainable Development (WBCSD)/WRI GHG protocol, DOE 1605(b), TCR, European Union Emissions Trading System, and Environment Canada's mandatory reporting guidelines). In addition, the ''higher tier'' (more accurate) site-specific methods use process-specific approaches. We explained at proposal (74 FR 16517) that we did not choose to propose these approaches based on the use of default values in general (such as the AISI approach) because the use of default values and lack of direct measurements results in a very high level of uncertainty (greater than ±25 percent), and default approaches would not provide site-specific estimates of emissions that reflect differences in feedstocks, operating conditions, fuel combustion efficiency, variability in fuels, and other differences among facilities.

We also stated at proposal that we decided not to finalize the proposal using methodologies that relied on default emission factors or default values for carbon content of materials because the differences among facilities described above could not be discerned, such default approaches are inherently inaccurate for site-specific determinations, and the use of default values is more appropriate for sector wide or national total estimates from aggregated activity data than for determining emissions from a specific facility.

We further note here that the AISI approach is not adequate for our reporting needs because it provides only a single emissions number aggregated from the numerous individual processes and combustion units at the iron and steel facility. In contrast, the approaches we are promulgating today for determining CO_2 emissions provide information at the process level and distinguish between combustion emissions and process emissions. Information at the process level is needed for many reasons, such as verification of the reported emissions from comparison with known ranges expected from various types of processes for a given production rate and emissions verification based on data for different plants for similar processes. Process-level reporting also provides information that will be useful in identifying processes that have reduced emissions over time and processes at specific plants that have the most potential for future reductions in emissions. In addition, the process-level reporting may provide information that can be used to improve methodologies for specific processes under future programs and to identify processes that may use a technology that could be the basis for an emission standard at a later time.

We developed estimates of costs for the proposed options for determining CO_2 emissions and concluded that the costs were reasonable. However, as explained below, we have revised the proposed options in response to comments, and these revisions significantly reduce the burden and costs of the carbon mass balance and site-specific emission factor methods while maintaining a similar level of accuracy.

Comment: Several commenters claimed that the proposed carbon mass balance method is unnecessarily burdensome because it requires weekly sampling, monthly analyses, and determining the monthly mass quantities of all process inputs and outputs. The commenters suggested that EPA allow the use of default values for carbon content, neglect streams that have very little or no carbon, drop the requirement for analysis by an ''independent certified laboratory,'' and allow the use of analyses from suppliers. One commenter recommended sampling and analysis for carbon content no more frequently than annually. The commenters stated that lime, dolomite and slag contain no appreciable carbon and do not need to be tracked, and that it is not necessary to account for the carbon in scrap that is charged to the furnace or in the steel product because they offset each other. One commenter noted that ''independent certified laboratory'' is not defined or explained, and another claimed that it is an unnecessary complication and expense because these carbon analyses are typically done in an in-house laboratory.

One commenter stated that the carbon mass balance equations were incomplete because they did not account for carbon removed by pollution control devices. Another commenter recommended that EPA use default carbon contents for different grades of steel scrap and noted that because companies already track the chemical content of each grade of scrap, highly accurate carbon calculations could be made with minimal additional burden.

Response: We received several useful suggestions for improving the carbon mass balance method without significantly decreasing the accuracy in the estimates. After a close review of the sampling and analysis requirements and comparing them to the requirements applied to other source categories in other subparts of this reporting rule, we concluded that the weekly sampling and monthly analysis of carbon content could be reduced in frequency to an annual analysis of all inputs and outputs at each facility. We also revised the rule to allow the use of carbon content analyses from the material supplier, which is consistent with what is required in other subparts using the carbon balance method. Carbon content does not vary widely at a given facility for the significant process inputs and outputs that contain carbon, and we continue to account for variations due to changes in production rate, which is likely a more significant source of variability. We continue to choose not to use default values for the reasons given in the previous comment response, and we have determined that an annual analysis of carbon content to provide plant-specific values is not burdensome because facilities already perform many such analyses. We agree that the analysis does not have to be performed by an independent certified laboratory, especially since we specify the analytical procedures that must be used by any laboratory, and we note that in-house laboratories may have more applicable experience in analyses of their particular process inputs and outputs.

We agree with the suggestion to evaluate carbon content by the grade or type of ferrous material charged to the furnace, and we incorporated a provision to calculate an average carbon content of ferrous materials charged based on the average weight percent of each type that is used. In addition, we have corrected the equations as suggested to account for carbon in the residue collected by emission control equipment. Finally, we agree that inputs and outputs that contain no carbon or an insignificant amount (i.e., contributing to less than one percent of the carbon in or out) do not need to be tracked in the carbon balance method.

Comment: Several commenters claimed that the site-specific emission factor method is not a viable option as proposed and should be streamlined to: (1) Eliminate annual re-testing, (2) reduce the test length from nine hours (or from nine production cycles for batch processes), (3) clarify that a separate test is not required for each grade of steel, and (4) remove the requirement to operate at 90 percent of capacity. One commenter stated that the most frequent re-testing currently required in operating permits is once every 2.5 years rather than annually. Another commenter noted that nine production cycles for certain small specialty steel producers would require 27 hours of testing for each grade of steel because each production cycle is three hours. Commenters stated that testing at 90 percent of production is problematic and is beyond their control because it is dictated by upstream and downstream production levels as well as economic conditions. In addition, capacity is difficult to determine because steelmaking furnaces do not have a nameplate capacity since it is determined by the iron production rate, how fast downstream processes (such as the caster) operate, process inputs, and product specifications that may require different operating cycle times.

One commenter questioned the value of the requirement to re-test if the carbon content of feed materials changes by more than 10 percent because this type of change could occur on a daily or weekly basis when the grade of steel being produced changes. Another commenter noted that EPA did not define what constituted a significant change in fuel type or mix and recommended that the provision be changed to 20 percent to allow for environmentally beneficial process improvements. Two commenters stated that the 10 percent threshold for re-testing is infeasible for steelmaking and sinter processes because of routine changes in the type of steel produced and the types of materials recycled to the sinter plant. The commenters requested that they be permitted to develop separate emission factors based on various modes that represent different operating scenarios or product categories. The commenters also recommended that EPA eliminate the 10 percent change threshold for re-testing and require that testing be conducted under conditions that are representative of normal operation. One commenter noted that the rule did not address how a site-specific emission factor would be developed when emissions from the EAF and argon-oxygen decarburization vessel are combined and routed to a single emission control device and stack.

Response: We further reviewed the testing requirement in other rules and those in operating permits and found that typical requirements (such as test requirements for particulate matter) include 3 one-hour runs or production cycles for representative testing of process emissions. Consequently, we are revising the testing requirements to three hours or three production cycles. We also agree with the commenters who noted that different routine operating modes may result in different levels of CO_2 emissions, and it is necessary to develop separate emission factors for these different operating conditions. Consequently, we have dropped the 10 percent re-testing threshold and instead require that separate emission factors be developed for each of different routine operating conditions that result in a change in CO_2 emissions by 20 percent or more.

We disagree that annual re-testing is excessive because testing for CO_2 emissions is much simpler and less costly than sampling for hazardous pollutants or for particulate matter, and annual sampling is consistent with our requirement for annual reporting. We agree that it is not necessary or always possible to test while operating at 90 percent of capacity for the reasons identified by the commenters. Instead, we are requiring that the test be performed based on representative performance, i.e., under normal operating conditions. We have revised the rule to clarify and provide options for testing when emissions from the EAF and argon-oxygen decarburization vessel are combined.

Comment: Several commenters asked EPA to clarify that CH_4 and N_2O emissions do not have to be reported for iron and steel production processes, and other commenters requested that CH_4 and N_2O emissions reporting not be required for the combustion of coke oven gas and blast furnace gas. Commenters noted that default emission factors for CO_2, CH_4, and N_2O were not provided in the tables in 40 CFR part 98, subpart C, and in the absence of such emission factors, asked if they would be required to test for these minor emissions.

Response: We have clarified that 40 CFR part 98, subpart Q does not require reporting of CH_4 and N_2O emissions from the iron and steel production processes because we expect these emissions (if any) to be very low, and we have no protocols for calculating them. However, emission factors are available in the 2006 IPCC guidelines for combustion sources, including the combustion of coke oven gas and blast furnace gas. We have added the IPCC default emission factors for CO_2 and N_2O for these process gases to the tables in 40 CFR part 98, subpart C, and we developed new emission factors for CH_4 based on the typical CH_4 content of coke oven gas (28 percent) and blast furnace gas (0.2 percent).

R. Lead Production

1. Summary of the Final Rule

Source Category Definition. The lead production source category consists of primary lead smelters and secondary lead smelters. A primary lead smelter is a facility engaged in the production of lead metal from lead sulfide ore concentrates through the use of pyrometallurgical techniques (smelting). A secondary lead smelter is a facility at which lead-bearing scrap materials (including but not limited to lead-acid batteries) are recycled by smelting into elemental lead or lead alloys.

Reporters must submit annual GHG reports for primary lead smelters and secondary lead smelters that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. For lead production, report the following emissions:

- CO_2 process emissions from each smelting furnace used for lead production.
- CO_2 combustion emissions from each smelting furnace used for lead production.
- N_2O and CH_4 emissions from each smelting furnace under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources) using the methodologies in subpart C.
- CO_2, N_2O, and CH_4 emissions from each on-site stationary combustion unit other than smelting furnaces under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

In addition, report GHG emissions for any other source categories at the facility for which calculation methods are provided in other subparts of the rule, as applicable.

GHG Emissions Calculation and Monitoring. To calculate annual process CO_2 emissions from an affected smelting furnace, the reporter must use the following methods, as applicable to the affected smelting furnace.

- For each affected smelting furnace with certain types of CEMS in place, the reporter must use the CEMS and follow the Tier 4 methodology (in 40 CFR part 98, subpart C) to measure and report under the Lead Production subpart (40 CFR part 98, subpart R) combined process and combustion CO_2 emissions.
- For other affected smelting furnaces, the reporter can elect to either (1) install and operate a CEMS and follow the Tier 4 methodology to measure and report combined process and combustion CO_2 emissions or (2) calculate annual process CO_2 emissions using a carbon mass balance procedure specified in 40 CFR part 98, subpart R. If using approach (2):

—Calculate emissions once per year using recorded monthly production data and the average carbon content for each smelting furnace input material determined by either using material supplier information or by annual analysis of representative samples of the material.
—Report process CO_2 emissions from each smelting furnace under 40 CFR part 98, subpart H (Cement Production), and report combustion CO_2 emissions from each kiln under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart R.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart R.

2. Summary of Major Changes Since Proposal

The major changes to the rule since proposal for lead production facilities were revisions to the carbon mass balance calculation procedure used by reporters for calculating process CO_2 emissions from affected smelting furnaces. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart R: Lead Production.''

• The frequency of performing the carbon mass balance calculations was revised to be required on an annual basis instead of the proposed monthly basis.

• The frequency of material carbon content sampling and analysis of each smelting furnace input material used for the carbon mass balance was revised to be performed by annual analysis of representative samples of the material instead of the proposed monthly basis.

• A *de minimis* carbon content level was added to exclude the need to account for carbon-containing materials contributing less than one percent of the total carbon into the smelting furnace in the carbon mass balance calculations.

• Data reporting procedures (40 CFR 98.186) were reorganized and updated to consolidate and clarify the emissions verification process. Some data elements for the carbon mass balance calculation were moved from 40 CFR 98.187 to 40 CFR 98.186, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.183 were added to 40 CFR 98.186 for clarity.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses specific to the lead production source category. Comments were received from one commenter regarding several topics. Responses to significant comments received are presented in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart R: Lead Production.''

Selection of Threshold

Comment: The commenter stated that Lead Production is not a source of significant GHG emissions and that EPA cannot assert that the Lead Production sector is a significant part of the stationary source combustion sector. The commenter notes that based on EPA's estimates in the TSDs for the proposal, estimated emissions from the Lead Production sector are 0.02 percent of the total estimated nationwide emissions from stationary fossil fuel combustion. Moreover, they argue that the combustion-related emissions from lead production are overstated by incorrect assumptions in the TSD. The commenter states that given Lead Production's relative contribution, it is not a significant source of emissions and should be eliminated from further consideration. The commenter further states that Lead Production is the only category evaluated where raising the threshold to the 100,000 ton level would results in zero facilities being covered. Accordingly, when the analysis shows that all facilities in a particular source category are not covered at the 100,000 ton threshold level, no insignificant GHG emitters in the category should be required to report under the Proposed Rule. The commenter noted that using the 100,000 threshold would not significantly reduce the coverage of emissions of EPA's rule, as the majority of sources identified would still have well over 90 percent of emissions from that source category covered under the 100,000 threshold. EPA provides no justification for imposing substantially more costs on industry for limited estimated benefits and small likelihood for regulation under the CAA. For these reasons, the Lead Production sector should be eliminated as a source category, and EPA should raise the threshold to 100,000 for non-source category facilities.

Response: We acknowledge this comment and concerns; however, the final rule retains the applicability requirement for this source category. We used information available to us for estimating GHG emissions from this industry which involved several assumptions related to the emission factors in the IPCC Guidance and other sources. As noted by the commenter, many of the underlying assumptions were based on an international perspective as opposed to the primary and secondary lead production industry in the U.S. The final rule contains a threshold of 25,000 metric tons CO_2e and only lead production facilities with emissions that equal or exceed 25,000 metric tons CO_2e will have to report emissions. In addition, the final rule now contains provisions allowing a reporter to cease reporting if the annual reports for a given facility demonstrate emissions less than specified levels for multiple years. These provisions apply to all reporting facilities, including those with lead production processes. *See* Section II.H of this preamble for the response on provisions to cease reporting.

We have further simplified the reporting requirement to further reduce burden for lead and similar industries by requiring annual as opposed to monthly sampling of carbon inputs. The purpose of this rule is to collect information on emissions sources for future policy development. Requiring reporting for these sources will provide EPA with valuable data to better characterize them and provide a more credible position if EPA elects to exclude these sources from future GHG policy analyses. Additionally, while some of these sources are currently believed to be small compared to the larger sources, they are not necessarily insignificant. The inclusion of reporting data for these sources is critical to support analysis of future policy decisions for lead production facilities.

When evaluating potential thresholds for reporting GHG emissions, we considered several thresholds between 1,000 and 100,000 metric tons CO_2e. We selected the 25,000 metric tons CO_2e threshold for reporting GHG emissions in order to achieve a balance between quantifying the majority of the emissions, while minimizing the number of facilities impacted. For example, at a 1,000 metric tons CO_2e threshold, 99 percent of emissions would be covered, with about 63 percent of facilities being required to report. The 100,000 metric tons CO_2e threshold captures no emissions or facilities while the proposed 25,000 metric tons CO_2e threshold achieves reporting of 92 percent of the GHG emissions while requiring less than 50 percent of the facilities to report. We consider this a significant coverage of the emissions, while impacting a relatively small portion of the industry. We believe the proposed threshold of 25,000 metric tons CO_2e represents the best option for ensuring that the majority of emissions are reported without imposing an unreasonable burden on the industry. *See* also Section II.E of this preamble and ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Selection of Reporting Thresholds, Greenhouse Gases, and De Minimis Provisions.''

Method for Calculating GHG Emissions

Comment: The commenter made several comments regarding the proposed procedures used to calculate process CO_2 emissions from smelting furnaces at secondary lead smelters. First, use of default emission factors should be allowed as a calculation method alternative because the smelting furnaces operated at used lead battery recycling facilities consistently process furnace feed materials with low carbon content variability. For affected sources using the carbon mass balance procedure, the frequency required for monitoring carbon content of the smelting furnace input materials should be reduced to reflect consistency and low carbon content variability of these materials.

Response: We decided not to finalize the proposal using methodologies for calculating CO_2 emissions from lead production that relied on published default emission factors or default values for carbon content of materials because the differences among individual lead production facilities could not be discerned using these factors. Consequently, the available default factors for lead production facilities are inherently less accurate for calculating smelting furnace process CO_2 emissions than using procedures that include use of site-specific material carbon data. Default approaches do not provide site-specific estimates of emissions that reflect differences in use of and variability in feedstocks, variability in fuels, operating conditions, fuel combustion efficiency, and other differences among facilities. For some carbon-containing input materials, such as lead scrap, representative published defaults do not exist. Therefore, the use of default values is more appropriate for sector wide or national total estimates from aggregated production data for multiple facilities rather than for providing an accurate representation of CO_2 emissions from a specific facility.

For the final rule, we did reduce the monitoring frequency for determining carbon contents of the smelting furnace input materials used for the carbon mass balance to be determined on annual rather than monthly basis. Facilities can determine carbon contents either by using material supplier information or by annual analysis of representative samples of the input materials. We agree that the carbon content for the significant input materials typically does not vary widely at a given lead production facility. Annual carbon content determinations will still provide representative carbon content data for the smelting furnace process CO_2 emissions calculations while minimizing the monitoring burden on reporters. We continue to account for process variations due to changes in production rate, which is likely a more significant source of variability in the CO_2 emissions from an affected smelting furnace during the year, by maintaining the requirement to measure and record monthly carbon containing input materials.

S. Lime Manufacturing

1. Summary of the Final Rule

Source Category Definition. Lime manufacturing plants (LMPs) engage in the manufacture of a lime product (e.g., calcium oxide, high-calcium quicklime, calcium hydroxide, hydrated lime, dolomitic quicklime, dolomitic hydrate, or other products) by calcination of limestone, dolomite, shells or other cacareous substances. This source category includes all LMPs unless the LMP is located at a kraft pulp mill, soda pulp mill, sulfite pulp mill, or only processes sludge containing calcium carbonate from water softening processes.

Lime kilns at pulp and paper manufacturing facilities need to report emissions under 40 CFR part 98, subpart AA (Pulp and Paper Manufacturing).

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble and meet the definition of lime manufacturing plants in 40 CFR 63.7081(a)(1).

GHGs to Report. For lime manufacturing, report the following emissions:

- Total CO_2 process emissions from all lime kilns combined.
- CO_2 combustion emissions from lime kilns.
- N_2O and CH_4 emissions from fuel combustion at each kiln under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources) using the methodologies in subpart C.
- CO_2, N_2O, and CH_4 emissions from each stationary combustion unit other than kilns under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).
- CO_2 collected and transferred off site under 40 CFR part 98, subpart PP (Suppliers of CO_2).

In addition, report GHG emissions for any other source categories at the facility for which calculation methods are provided in other subparts of the rule, as applicable.

GHG Emissions Calculation and Monitoring. For CO_2 emissions from kilns, facilities must use one of two methods, as appropriate:

- If all lime kilns at a facility have certain types of CEMS in place, the reporter must use the CEMS and follow the Tier 4 methodology (in 40 CFR part 98, subpart C) to measure and report under the Lime Manufacturing subpart (40 CFR part 98, subpart S) combined process and combustion CO_2 emissions.
- If CEMS meeting the specifications above are not in place for all kilns at the facility, the reporter can elect to either (1) install and operate a CEMS and follow the Tier 4 methodology to measure and report combined process and combustion CO_2 emissions from all lime kilns or (2) calculate CO_2 process emissions for each lime type using an emission factor for each lime type, the mass of lime produced, an emission factor for byproduct/waste (such as lime kiln dust and scrubber sludge), and the mass of byproduct/waste. If using approach (2):

—Each emission factor must be determined monthly for each lime type from monthly measurements of the calcium oxide and magnesium oxide content of the lime and stoichiometric ratios of CO_2 to each oxide in the lime.

—The emission factor for each lime byproduct/waste sold (such as lime kiln dust) must be determined monthly.

—The emissions from lime byproducts/wastes that are not sold (such as lime kiln dust and scrubber sludge) must be determined annually.

—The mass of each lime type produced and lime byproduct/waste sold (such as lime kiln dust) must be recorded on a monthly basis.

—The mass of each lime byproduct/waste not sold (such as lime kiln dust and scrubber sludge) must be recorded annually.
—Report process CO_2 emissions from all kilns combined under 40 CFR part 98, subpart S (Lime Manufacturing), and report combustion CO_2 emissions from each kiln under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart S.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart S.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart S: Lime Manufacturing.''

- The definition of lime manufacturing was revised to be similar to the definition in the Lime NESHAP at § 63.7081(a) and (a)(1).
- Reporting requirements were revised from a ''per kiln'' basis to ''all kilns combined''.
- The emissions calculations were revised to determine monthly emissions factors for each lime type and byproduct/waste type rather than for each kiln.
- Emission calculations for byproducts/wastes were added.
- The requirement to measure the calcium oxide and magnesium oxide content of byproducts/wastes on a monthly basis was changed to an annual basis for byproducts/wastes that are not sold.
- The correction factor for byproducts/wastes was removed from the rule.
- Additional direct measurement devices/methods are being allowed to include those currently in use by the industry.
- 40 CFR 98.196 was reorganized and updated. Some data elements were moved from 40 CFR 98.197 to 40 CFR 98.196, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.193 were added to 40 CFR 98.196 for clarity.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on lime manufacturing were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart S: Lime Manufacturing.''

Definition of Source Category

Comment: Multiple commenters requested more clarification in defining which sources and equipment are covered by the proposed rule. The rule defines the source category as a facility that contains ''a rotary lime kiln to produce a lime product.'' In addition, proposed 40 CFR 98.192(b) required sources to report emissions from ''each lime kiln and any other stationary combustion unit.''

Response: We have reviewed the rule language and decided the source category definition should provide more clarity. The source category is meant to include all kiln types used in the lime manufacturing industry; therefore, language in the final rule has been changed to be similar to the definition from the Lime NESHAP in 40 CFR 63.7081(a) and (a)(1). This Lime NESHAP effectively characterizes lime plants as those engaging in the manufacture of a lime product by calcination. The final rule requires all stationary combustion units to report under 40 CFR part 98, subpart C of the final rule.

Final rule language under 40 CFR 98.192 requires facilities to report CO_2, CH_4, and N_2O emissions from kilns used in the lime manufacturing process and all other combustion units at the lime manufacturing facility other than kilns. The language has also been clarified in 40 CFR 98.193. Facilities using CEMS for all lime kilns report combined process and combustion emissions from kilns under 40 CFR part 98, subpart S, according to the Tier 4 methodology in 40 CFR part 98 subpart C (General Stationary Fuel Combustion Sources). Facilities must follow the requirements of subpart C for estimating and reporting combustion related emissions for all other combustion units and report these emissions under subpart C. See Section III.C of this preamble for an overview of the requirements for stationary combustion units.

Selection of Proposed GHG Emissions Calculation and Monitoring Methods

Comment: Multiple commenters requested the language in 40 CFR part 98, subpart S be changed to allow emissions to be reported by ''all kilns combined'' instead of the proposed rule's request to report emission for each kiln. Multiple commenters further recommended that the process emissions calculations be changed to calculate emissions by the lime type produced as opposed to the current rule calculations which use a kiln specific emission factor. Two commenters stated that lime products are commonly aggregated at the plant making it difficult to estimate the amount of product produced at an individual kiln. These commenters stated that current lime plant configuration do not allow accurate kiln specific calculations.

Response: We have reviewed the common lime plant configuration and the currently proposed rule language and have decided that it is not necessary to require kiln-specific emissions reporting. We have observed that some kilns would have to retrofit weigh belt scales in the production line between kilns and storage silos, since they do not currently exist. Calculating emissions by kiln could increase the reporting burden for these facilities. According to one commenter, when kiln-specific emissions have been reported in the past, the data are usually derived by distributing the aggregated emissions among the kilns. Accurate measurements at the kiln level are rarely achieved. If this is true for most lime manufacturing facilities, the data does not necessarily provide a better estimate of emissions.

For the purposes of this rulemaking, reporting for all kilns combined will simplify and minimize the reporting burden without significant loss in accuracy because: (1) Kilns may produce more than one type of lime in a given reporting period, (2) emission factors are based on lime type, and (3) lime plants collect products in combined bagging areas (separated by lime type). The final rule language has been changed to require reporting by lime type from all kilns combined rather than all lime types for each kiln. This final rule language is consistent with the National Lime Association (NLA) Protocol, which was used as the basis for the methodology in the proposed rule. Information collected under this rule will help to inform future methodologies and determine whether kiln level reporting could be more appropriate for future reporting.

Comment: The proposed rule used a default correction factor in calculating lime product and byproduct/waste emissions. Multiple commenters suggested using the National Lime Association Protocol to determine lime product and by-product/waste process emissions. According to the commenters, this method is more precise due to the use of measured oxide values and stoichiometric ratios rather than correction factors.

Response: We have reviewed the proposed rule and NLA Protocol calculation methods and noted that the use of actual oxide measurements in calculating emissions from lime plants does not cause an additional burden to the reporter since this is a currently used practice. We also agree that the use of actual measurements is more accurate. Therefore, we have decided to remove the use of a correction factor in the final rule equations; emissions will be calculated from actual oxide measurements of each type of lime and calcined byproducts/wastes.

Monitoring and QA/QC Requirements

Comment: Multiple commenters asked that the language pertaining to allowable measurement devices for lime products and byproducts/wastes sold, be changed to include measurement devices commonly used in the lime industry. The current rule language requires weigh hoppers and belt weigh feeders as the measurement devices; the aforementioned commenters have identified bag, truck and rail scales as reliable (annually calibrated) direct measurement methods commonly used in the lime industry. In addition, commenters have requested lime byproducts/wastes not sold be calculated by a facility generation rate.

Response: After reviewing the rule language and common industry practices, we have decided to include other direct measurement devices used for accounting purposes, including but not limited to, weigh feeders, calibrated bag, rail or truck scales, and barge measurements. These methods are consistent with the original intent of the rule and add further clarification on measurement methods applicable to determine quantities of both lime produced and byproducts/waste generated.

In addition, reporters are required to perform an annual cross check by measuring lime products at the beginning and end of the year. For calcined byproducts/wastes not sold, a material balance approach that indirectly measures the generation rate should be used.

Comment: Multiple commenters asked that the language in 40 CFR part 98, subpart S pertaining to testing the chemical composition of each type of lime (including the byproducts and waste) be changed to allow testing by onsite lab facilities. Currently the rule specifies an ''off-site laboratory analysis'' but according to the commenter, commercial lime plants normally have onsite lab facilities.

Response: We agree that the analysis does not have to be performed by an independent certified laboratory, especially since we specify the analytical procedures that must be used by any laboratory, and we note that in-house laboratories may have more applicable experience in determining chemical composition. Reporters can determine whether to perform the test onsite or send the samples to offsite laboratory facilities. Therefore the language in the final rule has been changed.

Data Reporting Requirements

Comment: Multiple commenters requested the language in 40 CFR part 98, subpart S pertaining to reporting information to EPA be changed so that business sensitive information is kept in company records. Commenters agree that the production capacity, product quality (i.e., oxide content), emission factors and operating hours and days for each kiln, are required for emissions calculations but are concerned that making this information public would give information about their efficiency, productivity and capacity of kilns and facility.

Response: EPA reviewed CBI comments received across the rule (both general and subpart-specific comments) and our response is discussed in Section II.R of this preamble for legal issues. *Also, see* Section II.N of this preamble for the response to comments on the emissions verification approach.

We agree that annual operating hours and capacities are not used in the calculation of CO_2 emissions and these parameters have been moved to recordkeeping. This information can help to verify anomalies in emissions data if there were temporary shutdowns, etc.

We disagree that emission factors and product quality be maintained as records rather than be reported. Emission factors and product quality are used in calculations to establish the site specific rate of CO_2 emissions generated for each type of lime produced. Therefore these data are required in order to verify the CO_2 emissions that are being reported. This internal verification system ensures that the GHG emissions reported are accurate.

T. Magnesium Production

At this time EPA is not going final with the magnesium production subpart (40 CFR part 98, subpart T). For the immediate future, EPA believes that emissions of GHGs from magnesium production are sufficiently covered by the reporting requirements under 40 CFR part 98, subpart OO for Industrial Gas Supply. This information on U.S. production, imports, and exports of SF_6 will provide at least a general, order-of-magnitude check on consumption of SF_6 by magnesium production and other uses of SF_6. EPA will finalize the proposed reporting requirements for the magnesium production industry at a later date.

U. Miscellaneous Uses of Carbonate

1. Summary of the Final Rule

Source Category Definition. The Miscellaneous Uses of Carbonate source category consists of any facility that uses carbonates listed in Table U–1 of 40 CFR part 98, subpart U in manufacturing processes that emit carbon dioxide. The Table includes the following carbonates: Limestone, dolomite, ankerite, magnesite, siderite, rhodochrosite, or sodium carbonate. Facilities are considered to emit CO_2 if they consume at least 2,000 tons per year of the carbonates listed above and that are heated to a temperature sufficient to allow calcination to occur.

This source category does not include facilities processing carbonates or carbonate containing minerals consumed for producing cement, glass, ferroalloys, iron and steel, lead, lime, phosphoric acid, pulp and paper, soda ash, sodium bicarbonate, sodium hydroxide or zinc as CO_2 emissions from these processes are covered elsewhere in this rule.

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. For miscellaneous uses of carbonates, report the following emissions:

- Annual CO_2 process emissions for all miscellaneous uses of carbonates as specified in this subpart.
- CO_2, N_2O, and CH_4 emissions from carbonates used in sorbent technology and each stationary combustion unit on site under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

In addition, report GHG emissions for other source categories at the facility for which calculation methods are provided in the rule, as applicable.

GHG Emissions Calculation and Monitoring. Calculate process CO_2 emissions using annual carbonate consumption. All reporters must calculate the annual mass of carbonates used in processes which are heated to temperatures that allow calcination. If the annual amount of carbonates consumed is greater than 2,000 tons, CO_2 emissions must be calculated using either calcination fractions or the actual mass of input/output carbonates.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart U.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of analyses and calculations required for this source category.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart U: Miscellaneous Uses of Carbonates.''

- The source category definition was revised to exclude non-emissive uses of carbonates.
- A *de minimis* reporting threshold was added to exclude facilities with minor emissions based on annual carbonate consumption.
- The GHG calculation methodology was changed to allow reporters to determine emissions from the mass of carbonate input/output or calcination fractions.
- To improve the emissions verification process, 40 CFR 98.216 was reorganized and updated. Some data elements were moved from 40 CFR 98.217 to 40 CFR 98.216, and some data elements that a reporter must already use to calculate GHG as specified in 40 CFR 98.213 were added to 40 CFR 98.216 for clarity.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on miscellaneous uses of carbonates were received covering numerous topics. Most comments requested clarification on the definition of the source category and its applicability to affected sources. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart U: Miscellaneous Uses of Carbonates.''

Definition of Source Category

Comment: Multiple commenters requested that the source category be revised to exclude non-emissive uses of carbonates. Commenters stated that the source category is poorly defined, making it difficult to accurately assess its applicability to an industrial facility. Commenters noted a number of non-emissive uses as examples, such as the production of sodium bicarbonate and sodium hydroxide, during which sodium carbonates are used, but no carbon dioxide is released; onsite mixing of processed cement with aggregate, limestone used in poultry grit and as an asphalt filler; or adding sodium carbonate to a water softener system.

Response: The rule language has been modified to exclude non-emissive uses of carbonates. Non-emissive uses do not result in CO_2 emissions, such as adding sodium carbonate to a water softener system. Acid-induced releases of CO_2 from the use of carbonates are addressed in other subparts, where they are significant, such as Phosphoric Acid Production.

Selection of Threshold

Comment: Multiple commenters requested that a *de minimus* reporting threshold be added to exclude facilities with minor emissions. One commenter noted that some facilities use limestone and other carbonate as refractory in furnaces, and it is unclear whether or not this use of carbonates triggers 40 CFR part 98, subpart U, and at what level it is triggered.

One commenter noted that at a pharmaceutical manufacturing facility there would also be a significant listing of small operations and activities which use carbonate compounds in trace quantities, including the creation of reagent solutions, and wastewater treatment operations employing carbonate compounds for buffering, chemical precipitation, or solids stabilization. This commenter recommended that EPA implement a threshold of 2,000 tons per year of carbonates per facility, which would correlate to CO_2 emissions of about 1,000 tons per year.

One commenter requested that EPA incorporate a *de minimis* threshold to only include equipment where carbonate is present at greater than 10 percent by weight and heated to a temperature that allows for decomposition. This commenter suggested an alternative threshold, where EPA would require facilities to calculate CO_2 emissions from each type of carbonate used in quantities exceeding 2,000 tons per year.

Response: The rule language has been modified to specify that GHG emissions from miscellaneous carbonate use are required to be reported only from processes that consume at least 2,000 tons per year and, further, where the carbonates are heated to a temperature sufficient to allow the calcination reaction to occur. This modification to the definition of the source category allows facilities with minimal carbonate consumption and low amounts of GHG emissions to be excluded from reporting emissions.

Method for Calculating GHG Emissions

Comment: Multiple commenters requested that EPA allow emission calculations to be based on carbonate fraction of the product instead of calcination fractions.

Response: The rule has been changed to allow emission calculations by either the mass of carbonate input/output or calcination fraction. These methods should provide comparable estimates of emissions.

The calcination fraction method calculates the amount of CO_2 emissions based on the amount of each carbonate that is calcined during the process. The mass and calcination fraction of each carbonate are measured and used with a default CO_2 emission factor to determine CO_2 emissions.

The carbonate fraction method calculates the amount of CO_2 emissions as a mass balance between the input and output amount of each type of carbonate. The masses are measured and used with a default CO_2 emission factor to determine CO_2 emissions.

The mass of carbonate input/output is determined by use of the same plant instruments used for accounting purposes or by direct measurement. Calcination fractions can be measured by the appropriate industry consensus standards that require laboratory analysis of each carbonate type. Alternatively, a default value of one can be used as the calcination fraction.

Data Reporting Requirements and Records That Must Be Retained

Comment: One commenter requested that recordkeeping and reporting requirements be exempted for carbonates kept on-site for emergency purposes (not manufacturing or equipment), such as for neutralizing a chemical spill. This commenter explained that when used, these emergency reserves of carbonate material typically generate insignificant amounts of CO_2 and should therefore be excluded from reporting requirements.

Response: The final rule does not cover carbonates that are used in quantities of less than 2,000 tons per year and that are not heated to the point of calcination. Also, this subpart does not include requirements for calculating and reporting CO_2 emissions from acid neutralization. Therefore, the use of carbonates in the manner described is not covered by the final rule.

Comment: One commenter noted that the required records are duplicated in proposed 40 CFR 98.217(a) and 98.217(c), and requested that EPA revise this so as not to place unnecessary costs on facilities.

Response: EPA agrees that asking facilities to maintain records on procedures used to ensure the accuracy of monthly carbonate consumption will be duplicative with maintaining records of all carbonate purchases and deliveries. This is especially true if purchase records are used to determine monthly carbonate consumption. We removed this duplicative recordkeeping requirement from the rule.

To improve the emissions verification process, 40 CFR 98.216 was reorganized and updated. Some data elements were moved from 40 CFR 98.217 to 40 CFR 98.216, and some data elements that a reporter must already use to calculate GHG as specified in 40 CFR 98.213 were added to 40 CFR 98.216 for clarity. All affected sources must follow the general recordkeeping provisions under 40 CFR part 98.3(g) in subpart A.

Commenters may also want to review Section II.M for the response on the general recordkeeping requirements and Section II.N of this preamble for the response on the emissions verification approach.

V. Nitric Acid Production

1. Summary of the Final Rule

Source Category Definition. The nitric acid production source category consists of facilities that use one or more trains to produce weak nitric acid (30 to 70 percent in strength) through the catalytic oxidation of ammonia.

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. For nitric acid production facilities, report N_2O process emissions from each nitric acid train.

In addition, report GHG emissions for other source categories at the facility for which calculation methods are provided in the rule, as applicable. For example, report CO_2, N_2O, and CH_4 emissions from each stationary combustion unit on site under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

GHG Emissions Calculation and Monitoring. Reporters must calculate N_2O process emissions for each nitric acid train. Calculate the emissions by multiplying the site-specific emission factor for each train by the measured annual nitric acid production for that train. Determine the site-specific emission factor for each train through an annual performance test to measure N_2O from the absorber tail gas vent and the production rate for that train.

When N_2O abatement devices (such as nonselective catalytic reduction) are used, adjust the N_2O process emissions for the amount of N_2O removed using a destruction efficiency factor. The destruction factor is the destruction efficiency and can be specified by the abatement device manufacturer or can be determined using process knowledge or another performance test.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart V.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart V.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart V: Nitric Acid Production.''

- The re-testing trigger was changed. Performance testing to determine the N_2O emissions factor is required annually and whenever new abatement technology is installed. The performance test should be conducted under normal operating parameters.
- Equation V–2 was edited to correct a calculation error and to allow multiple types of abatement technologies.
- Reorganized and updated 40 CFR 98.226 to improve the emissions verification process. Some data elements were moved from 40 CFR 98.227 to 40 CFR 98.226, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.223 were added to 40 CFR 98.226 for clarity.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on nitric acid production were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart V: Nitric Acid Production.''

GHGs To Report

Comment: Multiple commenters asked that the language in 40 CFR 98.222(b) be clarified to include emissions under 40 CFR part 98, subpart V only from units that are 100 percent dedicated to nitric acid production to avoid double counting of combustion emissions.

Response: We appreciate the comments but have decided not to make any changes to 40 CFR part 98, subpart V. According to the applicability criteria in subpart C, all combustion unit emissions from nitric acid facilities (regardless of whether or not the combustion units are associated with nitric acid production operations) are to be reported under subpart C. There will be no potential for double counting of combustion emissions at the facility because Subpart V provides methods for reporting only the process emissions. *Also see* the preamble for responses on comments related to Subpart C (General Stationary Combustion).

Method for Calculating GHG Emissions

Comment: Multiple commenters asked that the requirement to repeat the annual performance test be removed. In the proposal, re-testing was triggered whenever the nitric acid production rate changed by more than 10 percent. Commenters asserted that production depends on demand for nitric acid and often varies by up to 20 percent.

Response: We appreciate the comments and have decided to eliminate re-testing. We believe that annual determination of the N_2O emissions factor is sufficient to accurately calculate N_2O emissions as long as the train equipment remains consistent over the year-long period (i.e., no installation of abatement technology).

Comment: Multiple commenters asked that alternative methods be allowed for calculating N_2O emissions from nitric acid production. Specifically the commenters asked that EPA allow the use of N_2O and flow CEMS to directly measure N_2O emissions and use the performance test to evaluate the CEMS accuracy. They also requested that EPA allow use of existing process flow meters, process N_2O analyzers to determine the amount of N_2O sent to control devices and conduct a performance test measuring control device destruction efficiency for each control device and then calculate N_2O emissions.

Commenters also asked that finalizing a methodology for N_2O stack testing for nitric acid units be delayed until EPA can coordinate with the commenters in formulating a more accurate means of measurement from these sources.

Response: We agree that there are other accurate means of determining N_2O emissions, such as N_2O CEMS. The final rule has been changed to allow alternative test methods, in addition to the proposed methods. Any alternative must be approved by the Administrator before being used to comply with this rule. An implementation plan that details how the alternative method will be implemented must be included in the request for the alternative method. Currently there is no EPA method for using N_2O CEMS. EPA understands the need to further evaluate and establish alternative comparable or potentially more accurate methods for sources to use in calculating N_2O emissions from nitric acid production and will address this in future rulemakings or amendments to rulemaking. Until the method is approved, facilities must use the alternatives proposed in the rule for a performance test. At minimum the performance test will help to QA/QC alternative methods currently used to monitor N_2O emissions (including N_2O CEMS).

The final rule allows the use of existing process flow meters and process knowledge in the determination of the destruction efficiency of N_2O abatement technologies. This parameter is often based on site-specific knowledge of operations in combination with manufacturer specifications. We believe that using existing methods reduces the potential cost impacts of this rulemaking and that it is in the best interest of the facilities that required parameters be accurately measured.

Comment: Multiple commenters asked that Equation V–2 be edited to follow the summation format used in the IPCC Tier 2 methodology. The current format does not allow for multiple abatement technologies (including no abatement).

Response: We agree with this comment. The equation in the proposed rule contained an error and did not allow for multiple abatement technologies. The final rule contains a corrected version of the equation.

Data Reporting Requirements

Comment: Multiple commenters argued that the annual production rates, capacity and operating hours are considered CBI and should not be reported. The commenters asked that this information be maintained by the facility and made available to the Agency upon request.

Response: We reviewed CBI comments received across the rule (both general and subpart-specific comments) and our response is discussed in Section II.R of this preamble and in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues.'' *See also* Section II.N of this preamble for the response on the emissions verification approach.

We agree that annual operating hours are not used in the calculation of N_2O emissions and this parameter has been moved to recordkeeping. However, this parameter is still important for emissions verification. This information can help to verify anomalies in emissions data if there were temporary shutdowns, etc.

We disagree that production be maintained as records rather than be reported. Nitric acid production is a parameter in the method for determining annual N_2O emissions so we need production rate in order to verify the N_2O emissions that are being reported. The internal verification system ensures that the GHG emissions reported are as accurate as possible.

We disagree that capacities be considered confidential information. During the data gathering process, we located multiple publicly available sources that included production capacities for nitric acid production facilities. Capacity information can help EPA determine a reasonable range within which reported emissions should be. We agree that capacities are not used in the calculation of N_2O emissions; however, this is still an important parameter for verifying emissions. Therefore, this parameter has been moved to recordkeeping.

W. Oil and Natural Gas Systems

At this time, EPA is not going final with the fugitive and vented methane emissions from the oil and gas sector under 40 CFR part 98, subpart W. As EPA considers next steps, we will be reviewing the public comments and other relevant information.

EPA received a number of lengthy, detailed comments regarding 40 CFR part 98, subpart W. Commenters generally opposed the proposed reporting requirements and thought they would entail significant burden and cost. For example, many commenters asserted that use of direct measurement to collect data required under 40 CFR part 98, subpart W would entail significant burden and that the proposal lacked standards for leak detection and measurement equipment. In many cases, commenters provided alternative approaches to the reporting requirements proposed by EPA such as the use of emission factors and/or reducing the number of sources and sites requiring direct measurement e.g., through statistical sampling. In addition to comments on burden, commenters requested clarification from EPA on a number of proposed reporting provisions.

As EPA received extensive comments on this subpart, EPA plans to take additional time to perform additional analysis and consider alternatives to data collection procedures and methodologies. These alternatives will provide similar coverage of vented and fugitive methane and other GHG emissions in the oil and gas sector, while concurrently taking into account industry burden. As stated in Section V.W of the preamble to the proposed rule (74 FR 166606, April 10, 2009), EPA will also consider the inclusion of GHG reporting from other sectors of the oil and gas industry.

Where applicable, EPA will also consider the applicability of engineering estimates, emissions modeling software and emissions factors rather than relying so extensively on the use of direct measurement. EPA will consider optimal methods of data collection in order to maximize data accuracy, while considering industry burden.

X. Petrochemical Production

1. Summary of the Final Rule

Source Category Definition. The petrochemical production source category consists of all processes that produce acrylonitrile, carbon black, ethylene, ethylene dichloride, ethylene oxide, or methanol, with certain exceptions. Exceptions include processes that produce a petrochemical as a byproduct, processes that produce methanol from synthesis gas when the annual mass production of hydrogen or ammonia exceeds the annual mass of methanol produced, direct chlorination processes operated independently of oxychlorination processes to produce ethylene dichloride, processes that produce bone black, and processes that produce a petrochemical from bio-based feedstock.

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. For petrochemical production facilities, report CO_2, CH_4, and N_2O process emissions from each petrochemical production unit. Process emissions include CO_2 generated by reaction in the process. Process emissions also include CO_2, CH_4, and N_2O emissions generated by combustion of off-gas from the process in stationary combustion units and flares. For some of the GHG emission calculation and monitoring options, 40 CFR part 98, subpart X references procedures in 40 CFR part 98, subpart C for calculating emissions from stationary combustion sources, and it references procedures in 40 CFR part 98, subpart Y for calculating emissions from flares.

In addition, report GHG emissions for other source categories at the facilities for which calculation methods are provided in the rule, as applicable. For example, report CO_2, N_2O, and CH_4 emissions from each stationary combustion unit on site that does not burn process off-gas under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources). The quantity of CO_2 captured must also be reported by following the requirements of 40 CFR part 98, subpart PP.

GHG Emissions Calculation and Monitoring. CO_2 process emissions from petrochemical production must be determined by one of three methods. Process emissions include emissions from CO_2 generated by chemical reactions in the process and from the combustion of process off-gas and liquid wastes.

One emission calculation option is to route all process vent emissions to one or more stacks and use CEMS to measure the CO_2 emitted from each stack (except flare stacks). For each stack that includes emissions from combustion of process off-gas, reporters must calculate CH_4 and N_2O emissions by the procedures specified in 40 CFR part 98, subpart C. For each flare, the final rule requires CO_2, CH_4, and N_2O emissions to be calculated using the procedures in 40 CFR 98.253(b) (Petroleum Refineries). If CO_2 CEMS are used on all subject stacks, even if the CEMS were installed for reasons other than compliance with this rule, then the rule requires the use of this reporting option.

A second emission calculation option is to use a mass balance. Under this option, the quantity of each carbon-containing feedstock added to the process and the quantity of each carbon-containing product produced by the process must be measured for each calendar month, or it may be calculated based on measured changes in the liquid level in storage tanks. The carbon content of each feedstock and product also must be determined at least once per month. The carbon content may be measured directly, or it may be calculated based on measurements of the composition and known compound molecular weights. Under this option, the procedures for products also apply to byproducts and liquid organic wastes that are not combusted onsite. To prevent double-counting of combustion emissions, this option specifies that the procedures for stationary combustion sources in 40 CFR part 98, subpart C apply only to the supplemental fuel (e.g., natural gas) burned in combustion units that supply energy needs for petrochemical processes. The final rule specifies numerous measurement method options and related calibration requirements in 40 CFR 98.244. To potentially minimize the sampling and analysis burden, the final rule, like the proposed rule, includes an option that allows reporters to assume a feedstock or product is always 100 percent pure if they determine that the specified compound is always present at greater than 99.5 percent.

A third emission calculation option is available only for ethylene processes. Because nearly all process emissions from this process are from combustion of process off-gas, the final rule allows calculation of emissions from all stationary combustion units that burn process off-gas (with or without supplemental fuel) in accordance with the Tier 3 or Tier 4 procedures in 40 CFR part 98, subpart C. In addition, this option requires CO_2, CH_4, and N_2O emissions from each flare to be calculated using the procedures in 40 CFR 98.253(b) (Petroleum Refineries).

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR 98.246.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR 98.247.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart X: Petrochemical Production.''

- The definition of the source category was changed to exclude ethylene dichloride production by the direct chlorination process alone from the petrochemical production source category because the only GHG emissions from this process are from the combustion of supplemental fuel and the combustion of hydrocarbon emissions in air pollution control devices. Ethylene dichloride produced by both direct chlorination and oxychlorination in the ''balanced process'' is still part of the source category.
- For the mass balance option, the measurement and emission calculation frequency was changed from weekly to monthly.
- For ethylene processes, an alternative was added to the mass balance option that allows reporters to calculate emissions from stationary combustion sources that burn ethylene process off-gas (with or without supplemental fuel) using the Tier 3 or Tier 4 procedures in 40 CFR part 98, subpart C. This includes all such combustion units, including units that supply energy to processes other than the ethylene process. This option does not affect requirements for stationary combustion sources related to ethylene processes that burn no process off-gas; emissions from these combustion units still must be calculated using the methods in any applicable Tier in 40 CFR part 98, subpart C.
- The reporting requirements in 40 CFR 98.246 were reorganized and updated to facilitate the emissions verification process, simplify and clarify requirements, and address requirements for the new monitoring option for ethylene processes.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Many comments on petrochemical production were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart X: Petrochemical Production.''

Definition of Source Category.

Comment: Several commenters stated that ethylene production should be removed from the petrochemical production source category because essentially all GHG emissions from such processes are from combustion sources, which would be subject to reporting under 40 CFR part 98, subpart C regardless of whether the process is included in the petrochemical production source category. According to two commenters, using a mass balance approach is irrelevant and confusing because ethylene processes have no normal process vents. One commenter noted that methane is produced in ethylene processes, but the vast majority is returned as fuel within the plant or another plant at the same site and thus would produce CO_2 emissions only when combusted. Another commenter noted that off-gas from ethylene processes that are co-located with a petroleum refinery or other chemical plants is sent to the fuel gas system where it is mixed with other process gases from non-ethylene units in a fuel gas blend drum and then distributed to combustion units throughout the refinery and/or chemical plant. According to two commenters, the mass balance approach is onerous due to the number of product streams that would have to be measured, and the results of a mass balance most likely would be less accurate than a fuel combustion methodology. These two commenters also noted that calculating GHG emissions based on fuel combustion is the methodology used currently by most ethylene units. One commenter suggested that as an alternative to excluding ethylene units from the petrochemical production source category, EPA could add an emission calculation methodology to 40 CFR part 98, subpart X that would allow facilities to calculate combustion emissions based on fuel consumption.

Response: As one commenter noted, methane (and other light ends) are generally burned in combustion units to supply energy needs for the ethylene process itself and possibly other processes. Emissions from combustion of these process off-gases are process emissions that are intended to be reported under 40 CFR part 98, subpart X. At facilities where the ethylene process off-gases are not mixed with off-gas from other processes, we do not believe that the mass balance approach is illogical; the flows and carbon contents of feedstocks and products can be determined for an ethylene process, and the resulting values can be used in the mass balance equations, just as they can for any other petrochemical process. Furthermore, we do not know if the views of the commenters reflect the views of all ethylene manufacturers. Therefore, we have retained ethylene in the petrochemical production source category, and we have retained the mass balance option in the final rule.

Although we still think a mass balance approach is appropriate and valid for ethylene processes, we have also evaluated combustion-based methodology options for the final rule. Given that the cracking and separation operations generate negligible CO_2, we agree with the commenters that the only significant source of emissions in ethylene production is from combustion operations. One concern we have with using the Tier 1 and Tier 2 methodologies in 40 CFR part 98, subpart C is that they rely on default emission factors and company records (rather than measurements) of fuel flow. Given the variety of feedstocks and the corresponding variety in process off-gas, we do not believe default emission factors or fuel flow based on company records are appropriate. Therefore, we rejected the Tier 1 and Tier 2 methodologies. On the other hand, Tier 3 requires measurement of the total fuel flow and relatively frequent measurement of the carbon content of the fuel. Using CEMS to measure CO_2 emissions (i.e., the Tier 4 methodology in 40 CFR part 98, subpart C) is also a good way to measure CO_2 emissions from any combustion unit. Therefore, we determined that use of the Tier 3 or Tier 4 methodology is acceptable for calculating emissions from combustion units that burn ethylene process off-gas (with or without mixing with supplemental fuel), and these options are included in the final rule. In addition, because the methodology used for calculating emissions from one combustion unit has no bearing on the emissions from any other combustion unit, the final rule states that a facility is not required to use the same Tier for each stationary combustion unit.

Comment: One commenter requested that EPA remove ethylene dichloride (EDC) from the petrochemical source category because EDC is not manufactured using a fossil fuel-based feedstock (e.g., crude oil, naphtha, natural gas condensate, methane, or other fossil fuel-based chemicals), no GHGs are used in the manufacturing process, and only a trace amount of CO_2 is generated in the process. Another commenter requested clarification that EDC produced as an intermediate in the production of vinyl chloride monomer is not part of the petrochemical source category because the entire process is considered to be an ''integrated process'', and the primary product of the process is not EDC. The commenter noted that the term ''primary product'' is also used in the Hazardous Organic NESHAP (HON) (40 CFR part 63, subpart F), but it has a different definition. To avoid confusion created by multiple definitions for the same term, the commenter urged EPA to consider alternatives to the concept of primary product for determining applicability of an integrated process.

Response: EDC is produced by two processes. In one process, the direct chlorination process, ethylene is reacted with chlorine to create EDC. As the commenters noted, reactions in this process produce negligible CO_2 emissions and no other GHG emissions. The only GHG emissions associated with this process are from the combustion of process off-gas and supplemental fuel. We have determined that monitoring and reporting of these emissions will be required under 40 CFR part 98, subpart C. Therefore, we have removed this process from the petrochemical source category.

In the second EDC process, the oxychlorination process, ethylene is reacted with hydrochloric acid to create EDC and water. Some of the ethylene, however, oxidizes to CO_2 and water in a competing side reaction. All facilities in the United States (U.S.) that operate this process operate it as part of an integrated process that includes vinyl chloride monomer production and a direct chlorination process. This integrated process is called a ''balanced process''. Although available estimates suggest the amount of CO_2 emitted is small relative to emissions from combustion, we do not have data to support such estimates. Furthermore, even if small relative to other sources, the total amount is not necessarily insignificant. We continue to believe information about these emissions is needed in order to support future policy decisions regarding petrochemical processes. Therefore, we have not removed EDC production by the balanced process from the petrochemical production source category.

In the proposed rule, an ''integrated process'' was defined as ''a process that produces a petrochemical as well as one or more other chemicals that are part of other source categories'' subject to reporting under 40 CFR part 98. This concept does not apply to production of EDC as an intermediate that is used in the onsite production of vinyl chloride monomer because vinyl chloride monomer production is not a source category that is subject to reporting under 40 CFR part 98. We used general language in the proposed rule that would apply to various integrated process scenarios, but the only scenario we know of that meets these conditions is methanol production from synthesis gas that is sometimes also used to produce hydrogen and/or ammonia (both of which are subject to reporting under other subparts in 40 CFR part 98). Because this is the only situation where the ''integrated process'' concept would apply, we decided to replace it in the final rule with language in 40 CFR 98.240 that explicitly states the applicability determination procedures for a process that produces methanol, hydrogen, and/or ammonia from synthesis gas. Thus, the term ''primary product'' has also been removed from the final rule, which eliminates the potential conflict with the definition in the HON.

Method for Calculating GHG Emissions

Comment: Two commenters stated that the proposed CEMS requirements are overly restrictive. According to these commenters, a facility should have the option to install a CEMS on one or more sources without being required to have a CEMS on all sources associated with a petrochemical production process. For example, the commenters suggested that a facility should have the flexibility to use a CEMS on a large emission point while being allowed to use the combustion equations and/or the mass balance approach for smaller emission points in the process (e.g., start-up heaters and steam jet exhausts from distillation columns operating under vacuum).

Response: If some emissions were from stacks monitored with CEMS and all other emissions were from combustion units without CEMS, it would be possible to use a combination of CEMS and the combustion equation methodology to calculate the total GHG emissions from a petrochemical process. However, this scenario is unlikely, which means other methodology would be needed to estimate emissions from other emission points (e.g., the steam jet exhausts cited by the commenters). It is not clear to us how the mass balance methodology would be used to estimate these other emissions because the mass balance relies on knowledge of the total carbon input to the process and the total amount of carbon in all products (and organic liquid wastes); the difference is assumed to be the total CO_2 emissions. Theoretically, other methodology could be developed to calculate emissions from specific other emission points, but the commenter has not suggested other techniques. Therefore, the final rule does not include an option to mix CEMS with other methodology for a given process unit.

Comment: According to several commenters, weekly measurements of feedstocks and products are burdensome or unwarranted. Two commenters suggested changing the frequency to monthly because monthly accounting would align better with existing industry accounting procedures, reduce the burden, and provide 12 high-quality estimates per year. One commenter suggested monthly mass balance calculations for carbon black facilities because the emissions from a carbon black manufacturing facility do not vary significantly from week to week. Another commenter requested a provision to allow the reporter to determine a sampling frequency that is consistent with the variability of the stream.

Response: We are sensitive to the burden imposed by the rule and want to minimize it when possible. Based on the results of an uncertainty analysis (see memorandum entitled ''Monte Carlo Simulation of Uncertainty in Monitoring Frequency for Mass Balance Option for Petrochemical Production Facilities'' in the docket) we believe longer monitoring periods will not significantly compromise the monitoring results for the mass balance option. Therefore, the mass balance option in the final rule requires monthly monitoring instead of the proposed weekly monitoring.

Data Reporting Requirements

Comment: Two commenters stated that the proposed reporting requirements are excessive, particularly information such as each carbon content measurement and information on the calibration of each flow meter. According to the commenters, submitting this information will not improve the overall quality of the GHG emission calculation, and it is not necessary because the facilities are required to certify that the submitted information is true, accurate, and complete. Therefore, the commenters recommended that facilities be required to retain records of such information rather than submit it in reports.

Response: A primary reason that additional information beyond annual emissions must be reported is so that EPA can verify the results. To facilitate the emissions verification process, 40 CFR 98.246 was reorganized and updated. For example, the final rule requires reporting of all input data used in the emission calculation equations, not just the carbon content values and the annual quantities, because this information is needed so the calculations can be reproduced and confirmed as part of the emissions verification process. Note, however, that any increase in the burden to report flow measurements has been offset by the reduction in monitoring frequency from weekly to monthly. The reporting requirements in the final rule for the mass balance option also have been simplified and clarified by replacing the requirement to submit all information related to uncertainty estimates with a requirement to submit only the dates and summarized results of measurement device calibrations. The estimated accuracy of measurement devices and the technical basis for such measurements must also be documented as part of the monitoring plan that is maintained onsite. The reporting section also was updated to include reporting requirements for the new monitoring option for ethylene processes.

Y. Petroleum Refineries

1. Summary of the Final Rule

i. Source Category Definition

Petroleum refineries are facilities that produce gasoline, gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt (bitumen) by the distillation of petroleum or the redistillation, cracking, or reforming of petroleum derivatives. The definition of petroleum refineries excludes facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation), regardless of the products produced.

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

ii. GHGs to Report

The refinery processes and gases that must be reported are listed in Table Y–1 of this preamble along with the rule subpart that specifies the calculation methodology that must be used.

TABLE Y–1—GHGS TO REPORT

For this refinery process . . .	Report emissions of the listed GHGs by following the requirements of the 40 CFR part 98, subpart indicated . . .		
	CO_2	CH_4	N_2O
Stationary combustion	C	C	C
Flares	Y	Y	Y
Catalytic cracking	Y	Y	Y
Traditional fluid coking	Y	Y	Y
Fluid coking with flexicoking design	C/Y	C/Y	C/Y
Delayed coking	—	Y	—
Catalytic reforming	Y	Y	Y
Onsite and offsite sulfur recovery	Y	—	—
Coke calcining	Y	Y	Y
Asphalt blowing	Y	Y	—
Equipment leaks	—	Y	—
Storage tanks	—	Y	—
Other process vents	Y	Y	Y
Uncontrolled blowdown systems	—	Y	—
Loading operations	—	Y	—
Hydrogen plants (nonmerchant)	P	P	—

Key:
C = 40 CFR part 98, subpart C (General Stationary Combustion Sources).
P = 40 CFR part 98, subpart P (Hydrogen Production).
Y = 40 CFR part 98, subpart Y (Petroleum Refineries).
— = Reporting from this process is not required.

iii. GHG Emissions Calculation and Monitoring

Under 40 CFR part 98, subpart Y, petroleum refineries must calculate CO_2, CH_4 and N_2O emissions using the calculation methods described below for each refinery process.

For CO_2 emissions, reporters must use CEMS or specified calculation methods as follows:

- For refinery units with certain types of CEMS in place, reporters must use the CEMS and follow the Tier 4 methodology of 40 CFR part 98, subpart C to report combined process and combustion CO_2 emissions.
- For refinery units without CEMS in place, reporters can elect to either (1) install and operate a CEMS to measure combined process and combustion CO_2 emissions according to the requirements specified in 40 CFR part 98, subpart C or (2) calculate CO_2 emissions using the methods summarized below.

Flares. CO_2 emissions from flares must be calculated using the gas flow rate (either measured with a continuous flow meter or calculated using engineering calculations) and either: (1) At least weekly measured carbon content of the flare gas, or (2) at least weekly measured heat content of the flare gas and an emission factor provided in the rule. If the carbon content and heat content of the gas are not measured at least weekly, engineering estimates of heat content during normal flare use is allowed, but CO_2 emissions for each startup, shutdown, and malfunction event exceeding 500,000 standard cubic feet (scf) per day of flare gas must be calculated separately using engineering estimates of the quantity of gas discharged and the carbon content of the flared gas. CH_4 and N_2O emissions from flares must be calculated using the methods specified in 40 CFR part 98, subpart Y.

Catalytic Cracking Units, Fluid Coking Units, and Catalytic Reforming Units. CO_2 emissions must be calculated using the volumetric flow rate of the exhaust gas (measured or calculated) and hourly measured carbon monoxide (CO) and CO_2 concentrations in the exhaust stacks from the catalytic cracking unit regenerator and fluid coking unit burner from units exceeding 10,000 barrels per stream day. Catalytic cracking and fluid coking units below this threshold must use the required flow and gas monitors if they are in-place, but may use engineering estimates for determining CO_2 emissions if the required flow and gas monitors are not in place. Similarly, catalytic reforming units may use the flow and gas monitors required for large catalytic cracking and fluid coking units; alternatively, reporters may use engineering estimates based on the quantity of coke burned off, the carbon content of the coke (using either a measured or a default value), and the number of regeneration cycles. CH_4 and N_2O emissions may be measured or may be calculated using the CO_2 emissions and default emission factors. Fluid coking units that use the flexicoking design may account for their GHG emissions either by using the methods specified for traditional fluid coking units, or by using the methods for stationary combustion specified in 40 CFR part 98, subpart C.

Onsite and Off Site Sulfur Recovery. CO_2 emissions must be calculated using the volumetric flow rate of the sour gas (measured continuously or calculated from engineering calculations) and the carbon content of the sour gas stream (using a measured or a default value).

Coke Calcining Units. CO_2 emissions must be calculated from the difference between the carbon input as green coke and the carbon output as marketable petroleum coke and as coke dust collected in the dust collection system. The CH_4 and N_2O emissions from coke calcining units may be measured or calculated using the calculated CO_2 emissions and default emission factors.

Asphalt Blowing Operations. For uncontrolled asphalt blowing operations or asphalt blowing operations controlled by vapor scrubbing, CH_4 and CO_2 emissions must be calculated using a facility-specific emission factor based on test data or, where test data are not available, a default emission factor provided in the rule. For asphalt blowing operations controlled by a thermal oxidizer or flare, CH_4 and CO_2 emissions must be calculated by assuming 98 percent of the CH_4 and other hydrocarbons generated by the asphalt blowing operation are converted to CO_2.

Delayed Coking Units. CH_4 emissions from the depressurization of delayed coking vessels must be calculated using the method outlined below for other process vents. The emissions released during the opening of vessels for coke cutting operations must be calculated using the vessel parameters (height and diameter), vessel pressure, the number of times the vessel was opened, the void fraction of the coking vessel prior to steaming, and the mole fraction of CH_4 in the gas released (using a measured or a default value provided in the rule). The rule provides an alternative of using only the vessel parameter equation if no water or steam is added to the vessel after the vessel is vented to the atmosphere.

Other Process Vents. GHG emissions from other process vents that contain CO_2, CH_4, or N_2O exceeding concentration thresholds specified in the rule must be calculated using the volumetric flow rate, the mole fraction of the GHG in the exhaust gas, and the number of hours during which venting occurred.

Uncontrolled Blowdown Systems. CH_4 emissions from uncontrolled blowdown systems must be calculated using either the method specified for process vents or a default emission factor and the sum of crude oil and intermediate products received from off site and processed at the facility.

Equipment Leaks. CH_4 emissions from equipment leaks must be calculated using either default emission factors or process-specific CH_4 composition data and leak data collected using the leak detection methods specified in EPA's Protocol for Equipment Leak Emission Estimates.

Storage Tanks. For storage tanks covered by the requirements of this rule, the methodology used to calculate the CH_4 emissions depends on the material stored. For storage tanks used to store unstabilized crude oil, facilities must use either: (1) The CH_4 composition of the unstabilized crude oil (based on direct measurement or product knowledge) and the measured gas generation rate; or (2) an emission factor-based method using the quantity of unstabilized crude oil received at the facility, the pressure difference between the previous storage pressure and atmospheric pressure, the mole fraction of CH_4 in the vented gas (using either a measured or a default value), and an emission factor provided in the rule. For storage tanks used to store material other than unstabilized crude oil with a vapor-phase CH_4 concentration of 0.5 percent by volume or more, facilities must use either tank-specific methane composition data and applicable correlations in AP–42, Section 7.1 (as implemented in the TANKS Model (Version 4.09D) or similar models) or a default emission factor provided in the rule.

Loading Operations. CH_4 emissions from loading operations must be calculated using vapor-phase methane composition data and the method in Section 5.2 of AP–42: ''Compilation of Air Pollution Emission Factors.'' Facilities must calculate CH_4 emissions only for loading materials that have an equilibrium vapor-phase CH_4 concentration equal to or greater than 0.5 percent by volume. Other facilities may assume zero CH_4 emissions.

iv. Data Reporting

In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart Y.

v. Recordkeeping

In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart Y.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart Y: Petroleum Refineries.''

- The minimum monitoring frequency for flare gas heat value or carbon content was changed to weekly from daily. (For background on the selection of a weekly frequency, see memorandum entitled: ''Uncertainty in Flare Estimates Based on Sampling Frequency'' in the docket.) Engineering calculations are allowed in the final rule for reporters that do not monitor flare gas flow continuously or flare heating value or carbon content at least weekly.
- The minimum monitoring frequency for refinery fuel gas carbon content and molecular weight was changed to weekly from daily in 40 CFR part 98, subpart C for reporters that do not have continuous monitoring equipment, and we clarified in 40 CFR part 98, subpart Y that common (fuel) pipe monitoring is allowed for petroleum refineries.
- We added a flare combustion efficiency of 98 percent, and we revised the equation for flare CH_4 emissions to account for uncombusted methane.
- The final rule allows engineering calculations to determine CO_2 emissions for catalytic cracking units and fluid coking units below 10,000 bbl/stream day that do not have $CO_2/CO/O_2$ monitors already installed.
- The delayed coking unit depressurization emission equations and asphalt blowing equations were amended to address comments received.
- We added concentration thresholds for CO_2, CH_4 and N_2O from process vents below which GHG emissions are not required to be calculated and reported.
- The reporting requirements were updated to facilitate the emissions verification process.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on petroleum refineries were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart Y: Petroleum Refineries.''

Definition of Source Category

Comment: Several commenters expressed concern that EPA defined a Petroleum Refinery so broadly that it could be interpreted to include chemical facilities that use petroleum-based materials as raw materials. Of particular concern was the term ''* * * and other products * * *'' which many commenters interpreted to include the manufacture of chemicals, synthetic rubber, and a variety of plastics. One commenter also requested clarification that ''other products'' did not include sulfur, ammonia, or hydrogen sulfide. Several commenters requested clarification that the definition of petroleum refineries did not include lube oil production or fuel blending operations if the products were produced without distilling, redistilling, cracking, or reforming of the petroleum derivatives.

Response: We have revised and clarified the definition of petroleum refinery to list a few additional refinery products (specifically gasoline blending stocks and naphtha) and deleted the term ''or other products.'' We believe that this change clarifies that companies that use petroleum derivatives to make only petrochemicals, plastics, synthetic rubber, sulfur, or any other product other than those specifically listed are not considered petroleum refineries. We feel the definition also clearly excludes lube oil manufacturing provided the lube oil manufacturer does not distill, redistill, crack, or reform the petroleum derivatives at the facility.

Comment: Numerous commenters requested that many of the emission sources for which 40 CFR part 98, subpart Y required reporting were small and should not have to be reported. Several commenters noted that EPA's TSD for the Petroleum Refining Sector: Proposed Rule for Mandatory Reporting of Greenhouse Gases, indicates that 92.9 percent of the refining sector's GHG emissions come from two sources, combustion and catalytic coke operations. The remaining 7.1 percent of emissions come from eight distinct categories, including: Hydrogen plants (2.7 percent); Sulfur Plants (1.9 percent); Flaring (1.6 percent); Wastewater Treatment (0.43 percent); Blowdown (0.18 percent); Asphalt Blowing (0.10 percent); Delayed Coking (0.058 percent); Equipment Leaks (0.014 percent); Storage Tanks (0.007 percent); and Cooling Towers (0.003 percent). The commenters argued that the burden associated with the collection of data as prescribed in the proposed rule is not warranted for small sources and/or not consistent with EPA's stated intended purpose of the rule which is to support analysis of future policy decisions.

Response: The TSD estimates are based largely on engineering estimates without significant supporting data. For the smaller sources, we have provided very simple methods to calculate the GHG emissions from these sources to minimize the monitoring, recordkeeping, and reporting burden associated with these sources when no measurement data are available. However, requiring reporting for these sources will provide EPA with valuable data to better characterize them and provide a better record upon which to formulate decisions regarding whether to include or exclude these sources from future GHG policy decisions. Additionally, while some of these sources are currently believed to be small compared to the larger sources present at petroleum refineries, they are not necessarily insignificant. The inclusion of reporting data for these sources is critical to support analysis of future policy decisions for petroleum refineries.

Comment: Several commenters objected to the mandatory reporting of CH_4 and N_2O emissions within the Petroleum Refinery source category. Many commenters cited the TSD, which indicated that N_2O emissions account for 0.09 percent of the GHG emissions and CH_4 account for only 0.87 percent of the GHG emissions. The commenters argued that the measurement error for the larger sources (stationary combustion sources and catalytic cracking unit coke burn-off) exceeds the contributions of these sources. As such, the commenters stated that the burden associated with reporting these emissions is not warranted and/or not consistent with EPA's stated intended purpose of the rule which is to support analysis of future policy decisions.

Response: The TSD estimates for CH_4 and N_2O are based largely on engineering estimates without significant supporting data. We specifically require reporting of these various GHGs to obtain better data by which to support future policy analysis. Moreover, EPA has pending before it a petition to reconsider the recently revised New Source Performance Standard (NSPS) for petroleum refineries asking EPA to reconsider, among other things, whether to establish GHG standards under section 111 for refineries. As such, we have a keen interest in obtaining improved GHG emissions data in order to better analyze policy options. For instance, refineries are a significant source of NO_X emissions, but we have no data to determine the fraction of NO_X that is N_2O. With the increased use at refineries of NO_X control devices, such as low-NO_X burners, low excess air, selective catalytic reduction (SCR) systems, and selective non-catalytic reduction (SNCR) systems, it seems plausible that N_2O may be a more significant portion of a refinery's NO_X emissions. Thus, if a facility has measurement data for a source, the reporting of these data are important for better understanding the impact of current and future policy options. Consequently, we have provided additional alternatives that allow the use of measured N_2O (and CH_4) emissions or site-specific emission factors in addition to the default factors. Nonetheless, we have provided very simple default methods to calculate the emission of these GHGs when measurement data are not available. While emissions of CH_4 and N_2O may not be large comparatively, the reporting method for these pollutants is straightforward and commensurate with the anticipated emissions contribution.

Method for Calculating GHG Emissions

Comment: Several comments objected to the requirements for flares, particularly the requirements for SSM events. Some commenters also stated that daily sampling was too burdensome. The commenters suggested that flare emissions be dropped from the rule or that refineries be allowed to perform a one-time calculation. One commenter noted that the proposed equation did not account for flare combustion efficiency, which was inconsistent with other subparts, and recommended that a flare efficiency factor be added to the equation to calculate the CO_2 emissions from flares.

Response: EPA needs accurate data on flare emissions to better understand this emission source, as flare use can vary significantly from day-to-day and year-to-year. Use of flares is too episodic and variable to allow a one-time calculation. However, we recognize that flares may contribute about two percent of a refinery's GHG emissions. Therefore, we sought to reduce the burden associated with the flare monitoring and reporting requirements. As proposed, special calculations for SSM events were only required if daily measurement data were not available. In this final rule, we allow weekly monitoring of flare use without triggering special SSM event calculations, which should lessen the burden associated with calculating flare emissions while not significantly changing the accuracy of the data. Additionally, we included a threshold flaring rate of 500,000 scf/day for SSM events. Only SSM events exceeding this gas flare rate require special SSM calculations in the final rule. Some consent decree requirements and State rules require root cause analysis and quantification of emission events exceeding 500,000 scf/day. We consider events of this magnitude to be significant and believe a separate analysis is justified in addition to the procedures that apply to routine operation. We have also revised the equations for CO_2 and CH_4 to account for flare combustion efficiency.

Monitoring and QA/QC Requirements

Comment: Several commenters argued that the monitoring and QA/QC requirements were excessive and that EPA significantly underestimated the costs associated with complying with the reporting requirements under 40 CFR part 98, subpart Y. One commenter noted that existing facility CO_2 CEMS, HHV monitors, carbon content monitors, and flow meters are not necessarily for ''regulatory'' purposes and thus may not meet the accuracy requirements of the rule. The commenter suggested many more refineries would have to add or replace monitors as a result of the rule. Many commenters suggested EPA significantly underestimated the labor hours required to collect and analyze daily samples as well as to develop and implement a QA plan. Various commenters supplied labor or cost estimates for various requirements in the rule, including costs of implementing an LDAR program and flare SSM calculations. Several commenters stated that the requirement to use a CEMS for monitoring CO_2 from the catalytic cracking unit was expensive and burdensome, especially for small refineries that do not have a CEMS infrastructure.

Response: We have significantly revised our rule requirements for petroleum refineries and stationary combustion sources to reduce burden to the industry. We have provided in the final rule (in 40 CFR part 98, subpart C) a default emission factor for refinery (still) gas to allow combustion sources that combust refinery gas and meet the applicability requirements in 40 CFR part 98, subpart C to use Tier 2 methods. For sources that do not meet the Tier 2 requirements, weekly monitoring for refinery fuel gas under Tier 3 (40 CFR part 98, subpart C) and for flare gas (40 CFR part 98, subpart Y) is allowed. We have also re-assessed our costs based on the comments received and increased the labor hours estimated to collect and analyze samples, develop QA plans, and to perform QA/QC of existing equipment. We did review our QA/QC requirements and see no validity to the argument that our QA/QC requirements are so stringent that refineries will have to replace existing monitors to comply with the rule. While we note that some cost elements suggested by commenters are relevant and have been addressed in the changes in the labor estimates for sampling, analysis, and QA/QC as described above, other cost elements suggested by commenters are not relevant. For example, revisions of LDAR programs are not required under the rule; the proposed and final rule specifically provides a simple process-based emission factor approach for estimating CH_4 emissions from equipment leaks. We are cognizant that refineries with small catalytic cracking units are most likely to elect a compliance option under 40 CFR part 63, subpart UUU that does not require monitoring of coke burn-off, so these small refineries are most likely the facilities that would have been required to install monitoring equipment under the proposed rule. After reviewing these costs and impacts on the small refineries, we have allowed engineering calculations to determine CO_2 emissions for catalytic cracking units below 10,000 bbl/stream day that do not have CO_2/CO/O_2 monitors already installed.

Even though we have reduced the stringency of the rule in many places, our revised cost estimates indicate that the average cost per refinery is approximately 60 percent higher than projected at proposal. We believe our revised refinery costs accurately portray the burden associated with the final reporting requirements in 40 CFR part 98, subpart Y. Nonetheless, we continue to believe that the costs are reasonable for this rule, especially considering that petroleum refineries are among the larger sources of GHG emissions in the U.S.

Z. Phosphoric Acid Production

1. Summary of the Final Rule

Source Category Definition. The phosphoric acid production source category consists of facilities that use a wet-process phosphoric acid process to produce phosphoric acid. A wet-process phosphoric acid process line is any system that manufactures phosphoric acid by reacting phosphate rock and acid and is usually identified by an individual identification number in a CAA operating permit.

Reporters must submit annual GHG reports for Facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. Report CO_2 emissions from each wet-process phosphoric acid process line.

In addition, report GHG emissions at each facility for other source categories for which calculation methods are provided in the rule, as applicable. For example, report CO_2, N_2O, and CH_4 emissions from each stationary combustion unit on site under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

GHG Emissions Calculation and Monitoring. Calculate process emissions of CO_2 using one of two methods, as appropriate:

- Most reporters can elect to either (1) install and operating CEMS and follow the Tier 4 methodology (in 40 CFR part 98, subpart C) or (2) calculate CO_2 emissions based on monthly measurements of the mass of phosphate rock consumed and inorganic carbon content of each grab sample of phosphate rock.
- However, if process CO_2 emissions from phosphoric acid production are emitted through the same stack as a combustion unit or process equipment that uses a CEMS and follows Tier 4 methodology to report CO_2 emissions, then the CEMS must be used to measure and report combined CO_2 emissions from that stack. In such cases, the reporter cannot use the CO_2 calculation methodology outlined in approach (2) in the previous bullet.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart Z.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart Z.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart Z: Phosphoric Acid Production.''

- The rule was revised to allow the use of techniques from Part 60 and Part 63 for calculating the weight of phosphorous-containing rock.
- The missing data provisions were revised to allow the use of default inorganic carbon content values based on the origin of the phosphorous-containing rock, in addition to determining missing inorganic carbon contents of phosphate rock consumed using an arithmetic average of measured values from of inorganic carbon contents of phosphate rock of the appropriate origin preceding and following the missing data incident.
- 40 CFR 98.266 was reorganized and updated to improve the emissions verification process. Some data elements were moved from 40 CFR 98.267 to 40 CFR 98.266, and some data elements that are already used to calculate GHG emissions as specified in 40 CFR 98.263 were added to 40 CFR 98.266 for clarity.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments on phosphoric acid production were received covering numerous topics shown below.

Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart Z: Phosphoric Acid Production.''

Selection of Threshold

Comment: Multiple commenters asked that phosphoric acid production units not be included as an ''all-in'' category. According to the commenters, the facilities are very minor sources of GHG emissions. The commenter conceded that most (if not all) would still fall within the reporting threshold requirement, but asserted that it was unnecessary to include all phosphoric acid production units as regulated facilities regardless of the amount of emissions. The commenters stated that EPA inaccurately suggests that these units are major emitters of GHGs which could have significant impacts on these minor sources.

Response: We acknowledge the comments and concerns; however the final rule retains the ''all-in'' applicability requirement for this source category. The ''once in, always in'' provision has been removed. The final rule now contains provisions to cease reporting if annual reports demonstrate emissions less than specified levels for multiple years. These provisions apply to all reporting facilities, including those with phosphoric acid production processes. The purpose of this rule is to collect information on emissions sources for future policy development. Requiring reporting for these sources will provide EPA with valuable data to better characterize GHG emissions from phosphoric acid production and provide a more credible position if EPA elects to exclude these sources from future GHG policy analyses. We also believe that the accurate assessment of the emissions from phosphoric acid production will address the commenters' concerns about potential future impacts.

Commenters may also be interested in reviewing Section II.H of this preamble for the response on provisions to cease reporting.

Method for Calculating GHG Emissions and Monitoring and QA/QC Requirements

Comment: Multiple commenters asked that production measurements in this rule be consistent with the existing MACT and NSPS regulations for the phosphate industry. In these regulations, production measurement is determined by the mass of phosphate feed (as P_2O_5). Two commenters stated that the change would provide consistency, and ensure a reporting structure that fits with the actual practices of the industry.

Response: We agree with the commenters that consistency among EPA regulations is important. Therefore, the final rule allows for techniques from part 60 and part 63 to calculate the weight of phosphorous-containing rock. This request is consistent with the intent of the proposed rule. Under existing regulations in part 60 and part 63, phosphoric acid manufacturing facilities already measure the mass of phosphorous bearing feed on a ton/hour basis. This feed rate can be used to determine monthly phosphate rock consumption. Process CO_2 emissions from phosphoric acid production are calculated from the total phosphate rock consumption multiplied by the inorganic carbon content of that rock. Further, part 60 and part 63 establish the appropriate monitoring and QA/QC procedures for determining this feed rate.

Procedures for Estimating Missing Data

Comment: Multiple commenters asked that the final rule allow options for missing data. The commenters asked that the use of default carbon content values based on the origin of the rock be allowed if analytical data are unavailable. In addition, commenters requested that procedures be added for measurement of the mass of phosphate rock consumed, suggesting procedures similar to those in 40 CFR part 98, subpart C, the lesser of the maximum capacity of the system, the maximum rate the meter can measure, or best available estimate based on available process data.

Response: We agree with the commenters on this point. The final rule has been changed to allow the use of a default factor (by origin of the phosphate rock) for each missing value of the inorganic carbon content of phosphate rock. Use of a default carbon value in place of the missing data will provide a reasonable estimate of the total emissions from the facility and will avoid assuming the maximum possible facility emissions when no data are available. These default values have been added to the final rule in Table Z–1 of 40 CFR part 98, subpart Z.

Missing data procedures have also been added as suggested for missing monthly estimates of the mass of phosphate rock consumed consistent with the later recommendation. Again use of the best available data based on all available process data will avoid assuming the maximum possible facility emissions when no data are available. Facilities must document and keep records of the procedures used for all such estimates.

AA. Pulp and Paper Manufacturing

1. Summary of the Final Rule

Source Category Definition. This source category consists of facilities that produce market pulp (i.e., stand-alone pulp facilities), manufacture pulp and paper (i.e., integrated mills), produce paper products from purchased pulp, produce secondary fiber from recycled paper, convert paper into paperboard products (e.g., containers), or operate coating and laminating processes.

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. Table AA–1 of this preamble lists the GHG emission sources at pulp and paper manufacturing facilities for which GHG emissions must be reported along with the rule subpart that specifies the calculation methodology.

TABLE AA–1—GHGS TO REPORT

For pulp and paper mills ...	Report emissions of the listed GHGs by following the requirements of the 40 CFR part 98, subpart indicated ...					
	CO_2	Biogenic CO_2	CH_4	N_2O	Biogenic CH_4	Biogenic N_2O
Chemical recovery furnace at kraft and soda facilities	C	AA	C	C	AA	AA
Chemical recovery combustion units at sulfite facilities	C	AA	C	C	AA	AA
Chemical recovery combustion units at stand alone semi-chemical facilities	C	AA	C	C	AA	AA
Lime kilns of kraft and soda facilities	AA/C	AA	AA/C	AA/C	AA	AA
Makeup chemicals used in pulp mills	AA					

TABLE AA–1—GHGS TO REPORT—Continued

For pulp and paper mills ...	Report emissions of the listed GHGs by following the requirements of the 40 CFR part 98, subpart indicated ...					
	CO_2	Biogenic CO_2	CH_4	N_2O	Biogenic CH_4	Biogenic N_2O
Stationary combustion units	C	C	C	C	C	C

Key:
C = 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).
AA = 40 CFR part 98, subpart AA (Pulp and Paper Manufacturing).
AA/C = use 40 CFR part 98, subpart AA for GHG emission factor and subpart C to determine default High Heating Values.

GHG Emissions Calculation and Monitoring. Under 40 CFR part 98, subpart AA, reporters must calculate emissions from pulp and paper manufacturing facilities as follows:

• *Chemical recovery furnaces:* Calculate biogenic CO_2 emissions from combustion of biomass in spent pulping liquor using:

—Measured quantities of spent liquor solids fired, site-specific high heating value (HHV), and default or site-specific emission factors for each chemical recovery furnace located at kraft or soda facilities.

—Measured quantities of spent liquor solids fired and the carbon content of the spent liquor solids for each chemical recovery unit at sulfite or stand-alone semichemical facilities.

• Calculate CO_2 emissions from fossil fuels used in chemical recovery furnaces using direct measurement of fossil fuels consumed and default emission factors according to the Tier 1 methodology for stationary combustion sources in 40 CFR part 98, subpart C.

• Calculate CH_4 and N_2O emissions as the sum of emissions from the combustion of fossil fuels and the combustion of biomass in spent pulping liquor, as follows:

—For fossil fuel emissions, use direct measurement of fuels consumed, a default HHV, and default emission factors according to the methodology for stationary combustion sources in 40 CFR 98.33(c).

—For biomass emissions, use measured quantities of spent liquor solids fired, site-specific HHV, and default or site-specific emission factors.

—Lime kilns at kraft and soda facilities.

• *Lime kilns:* Calculate CO_2, CH_4, and N_2O emissions from combustion [21] of fossil fuels in pulp mill lime kilns using direct measurement of fossil fuels consumed and default emission factors and HHV found in 40 CFR part 98, subparts AA and C, respectively.

• *Makeup chemicals:* Calculate CO_2 emissions from the use of makeup chemicals using direct or indirect measurement of the quantity of chemicals added and ratios of the molecular weights of CO_2 and the makeup chemicals.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart AA.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart AA.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart AA: Pulp and Paper Manufacturing.''

• Language was added to clarify that 40 CFR part 98, subpart AA GHG emissions are to be reported for makeup chemicals added in the chemical recovery areas of pulp mills (as opposed to makeup chemicals used at paper coating and laminating facilities).

• The frequency of measurements for the spent liquor solids mass fired (TAPPI Test Method T 650), heating value (TAPPI Test Method T 684), and carbon content (ASTM D5373–08) was reduced from monthly to annually.

• An option to use data from existing online solids meters to determine the annual mass of spent liquor solids fired is provided (in lieu of conducting an annual TAPPI Test Method T 650).

• The requirement to report quarterly data was eliminated.

• The reporting requirements were revised to specify units to standardize inputs into the data reporting system.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A number of comments on pulp and paper manufacturing were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart AA: Pulp and Paper Manufacturing.''

Definition of Source Category

Comment: Two commenters stated that literal interpretation of 40 CFR part 98, subpart AA could require any facility operating paper coating and laminating processes to report emissions for any system used to add makeup chemicals. The commenters requested that language be added to 40 CFR part 98, subpart AA to clearly exclude facilities not intended to be covered and which have not traditionally been part of the pulp and paper source category.

Response: Definitions of terms used in 40 CFR part 98, subpart AA are provided in 40 CFR 98.6 (in subpart A of part 98). The definition of ''makeup chemicals'' is specific to the chemical recovery areas of pulp mills and serves to limit the scope of the pulp and paper subcategory. As defined in § 98.6 (emphasis added):

''*Chemical recovery combustion unit* means a combustion device, such as a recovery furnace or fluidized-bed reactor where spent pulping liquor from sulfite or semi-chemical pulping processes is burned to recover pulping chemicals.''

''*Makeup chemicals* means carbonate chemicals (e.g., sodium and calcium carbonates) that are added to the chemical recovery areas of chemical pulp mills to replace chemicals lost in the process.''

[21] Biogenic CO_2 from the conversion of $CaCO_3$ to CaO in kraft or soda pulp mill lime kilns is accounted for in the biogenic CO_2 emission factor for the recovery furnace.

Thus, we disagree that the rule could be interpreted to require any facility operating coating and laminating processes to report emissions for any system used to add makeup chemicals. This was not the intent of the rule. Nevertheless, we have added language consistent with the definition of ''makeup chemicals'' to 40 CFR 98.270(b)(5) and 98.272(e) to further clarify that GHG emissions are to be reported for systems adding makeup chemicals ($CaCO_3$ and Na_2CO_3) in the chemical recovery areas of pulp mills.

Comment: Commenters stated the rule should include categorical exemptions for emissions from the combustion of non-condensable gases (NCG), stripper off gases (SOG), tall oil and turpentine (small sources of GHG that are difficult to measure). The commenters noted that these streams are of biogenic origin. One commenter described safety issues associated with sampling these gas streams.

Response: Pulp mill NCG, SOG, tall oil and turpentine were discussed in the Proposed Rule TSD for the pulp and paper manufacturing sector. The Proposed Rule TSD noted that process vent gases such as NCG and SOG and the byproducts tall oil and turpentine are derived from biomass. We acknowledge the safety and measurement issues described by commenters regarding sampling of NCG and SOG streams. No methods are specified in the rule for calculation of GHG associated with combustion of NCG, SOG, tall oil and turpentine. Thus, calculation of these emissions is not required and there is no need for categorical exemptions.

Method for Calculating GHG Emissions

Comment: Commenters stated that monthly measurements of the mass of spent liquor solids, HHV, and carbon content of spent liquor solids are unnecessary. The commenters requested that EPA either allow default fuel carbon content and heating value for spent pulping liquor, or reduce the frequency of measurements to annually or every two years. Commenters noted that spent liquor HHV and carbon content are measured from time to time but less frequently than monthly. In addition, one commenter pointed out that chemical recovery furnaces often have online solids meters installed to provide continuous measurement of the mass of spent liquor solids entering the furnace for safety and process control reasons. This commenter requested that EPA allow use of such continuous measurement devices instead of requiring monthly measurement of the mass of spent liquor solids with TAPPI Test Method T 650.

Response: We disagree with commenters that default fuel carbon content and high heating values should be allowed instead of measured values. These parameters are already measured by mills (though less frequently than monthly) and thus are available for use and more accurate than default values. We are reducing the frequency of fuel property measurements from monthly to annual. There is little monthly variation in fuel properties over the course of a year. Therefore, annual measurements are sufficient to develop site specific emission factors. This change also reduces the burden associated with complying with the rule. These changes have been incorporated throughout the text and equations of 40 CFR part 98, subpart AA.

In addition, the final rule allows use of either an annual measurement of the mass of spent liquor solids fired (with TAPPI Test Method T 650) or use of annual spent liquor solids data calculated from continuous measurements already performed for process control purposes (e.g., with existing online solids meters). If the annual spent liquor solids fired is determined using existing measurement equipment, then reporters must retain records of the calculations used to determine the annual mass of spent liquor solids fired from the continuous measurements in order to demonstrate, if necessary, that calculations where done correctly. Reporters must also document that these measurement devices have been regularly and properly calibrated according to the manufacturer's specifications.

Data Reporting Requirements

Comment: One commenter noted that presenting quarterly data in annual reports for pulp and paper manufacturing annual emissions, consumption of biomass fuels, and quantity of spent liquor solids fired is unnecessary for an annual reporting system.

Response: We have revised 40 CFR 98.276 and 98.277(a) to remove the requirement for providing quarterly details in the annual report. EPA agrees that requiring quarterly details was not necessary for ensuring the accuracy of data reported annually.

Comment: One commenter requested that the spreadsheets developed by the National Council for Air and Stream Improvement (NCASI) for the International Council of Forest and Paper Associations (ICFPA) be allowed as an option for facilities subject to the Rule to determine emissions. These spreadsheets segregate calculated GHG emissions into fossil fuel and biogenic categories. The commenter believes that tools like those developed by NCASI and others should be allowed as an option for facilities subject to the emission calculation requirements imposed by 40 CFR 98.3. This streamlined approach will provide the Agency with valid GHG emission data without imposing extraordinary capital and labor burdens on the industry.

Response: The ICFPA/NCASI tools were considered in developing the requirements of the GHG reporting rule. However, the ICFPA/NCASI spreadsheets, though valuable tools, are not broadly applicable to all industrial sectors covered under the GHG reporting rule, as are the monitoring, reporting, recordkeeping, and emissions verification requirements specified in 40 CFR 98.3. Additionally, these tools often use default factors and estimates, which differs from the approach proposed by EPA. The data collected from all subparts of the GHG reporting rule will be tabulated in EPA's electronic reporting system. This system will be used to verify emission calculations and will require specific data be reported in order to run the calculations used for verification. The tools suggested by the commenter, however, would only provide a total emission number. Consequently, EPA would not be able to check the underlying calculations for accuracy. The final GHG reporting rule reflects the data reporting requirements necessary for emissions verification by EPA. Edits to the reporting and recordkeeping language (40 CFR 98.276 and 98.277) of 40 CFR part 98, subpart AA were made to clarify calculation inputs and units of measure to be reported. As part of the implementation phase of today's final rule, EPA intends to prepare guidance documents to assist the industry in complying with the rule's requirements. In recognition of the fact that the pulp and paper industry has been using the ICFPA/NCASI spreadsheets, EPA will consider including in the guidance materials a comparison between these spreadsheets and EPA's electronic reporting system to reduce the burden on the industry and minimize confusion.

BB. Silicon Carbide Production

1. Summary of the Final Rule

Source Category Definition. The silicon carbide production source category consists of any process that produces silicon carbide for abrasive purposes.

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. Report process CO_2 and CH_4 emissions from all silicon carbide production furnaces or process units at the facility combined.

In addition, report GHG emissions for other source categories at the facility for which calculation methods are provided in the rule, as applicable. For example, report CO_2, N_2O, and CH_4 emissions from each stationary combustion unit on site under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

GHG Emissions Calculation and Monitoring. For CO_2 emissions, reporters must use one of the following methods, as appropriate:

• Most reporters can elect to calculate and report process CO_2 emissions from silicon carbide production processes by either (1) installing and operating CEMS and following the Tier 4 methodology (in 40 CFR part 98, subpart C) or (2) calculating emissions using the measured petroleum coke consumption and a monthly facility-specific emission factor. The facility-specific emission factor is the carbon content of the petroleum coke (provided monthly by the supplier or measured monthly using the appropriate test methods) adjusted for carbon in the silicon carbide product.

• However, if process CO_2 emissions from silicon carbide production are vented through the same stack as a combustion unit or process equipment that uses a CEMS and follows Tier 4 methodology to report process CO_2 emissions, then the CEMS must be used to measure and report combined CO_2 emissions from that stack. In such cases, the reporter cannot use the CO_2 calculation approach (2) outlined in the above bullet.

For CH_4 emissions, reporters must use the measured petroleum coke consumption and a default emission factor of 10.2 kilograms (kg) per metric ton of coke consumed.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart BB.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart BB.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart BB: Silicon Carbide Production.''

• The emissions calculation method under 40 CFR 98.283(b) was revised to require data on monthly petroleum coke consumption and monthly petroleum coke carbon contents rather than quarterly determinations.

• Missing data procedures were added under 40 CFR 98.285 for monthly parameters used to calculate emissions, including mass of petroleum coke, and carbon contents of petroleum coke.

• 40 CFR 98.286 was reorganized and updated to improve the emissions verification process. Some data elements were moved from 40 CFR 98.287 to 40 CFR 98.286, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.283 were added to 40 CFR 98.286 for clarity.

3. Summary of Comments and Responses

No specific comments were received pertaining to the proposed reporting requirements for silicon carbide production facilities. However, the proposed rule did not clearly specify how quarterly carbon contents should be determined. This determination should be made on a monthly basis as proposed for other chemical production processes where process emissions arise from use of petroleum coke, such as titanium dioxide production. Quarterly reporting of carbon contents of petroleum coke consumed for the quarter would have to be averaged from monthly data. For verification, EPA would require reporting of the monthly carbon contents of the petroleum coke. Therefore, we revised the emissions calculation method to directly require monthly petroleum coke consumption and monthly petroleum coke contents, rather than quarterly based on an arithmetic average of the monthly estimates to improve accuracy of emissions calculations. We have retained the flexibility in use of supplier data to determine carbon contents. We understand that most supplier data on carbon contents of petroleum coke is readily available and that businesses track production inputs and outputs on a monthly basis as a part of normal business practice or existing accounting procedures. The increased frequency of data collection from quarterly to monthly provides greater clarity and accuracy without significantly increasing burden. In addition, see the Section II.N of this preamble for an explanation of the emissions verification approach.

CC. Soda Ash Manufacturing

1. Summary of the Final Rule

Source Category Definition. A soda ash manufacturing facility is any facility with a manufacturing line that produces soda ash by either: calcining trona or sodium sesquicarbonate; or by using a liquid alkaline feedstock process that directly produces CO_2. In the context of the soda ash manufacturing sector, ''calcining'' means the thermal/chemical conversion of the bicarbonate fraction of the feedstock to sodium carbonate.

Soda ash produced from a liquid alkaline feedstock using sodium hydroxide does not emit process CO_2 and therefore is not subject to the requirements of Subpart CC. However, such facilities may be covered under Subpart C (General Stationary Combustion) if they meet the requirements of either § 98.2(a)(1) or (2).

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. For soda ash manufacturing, report the following emissions:

• CO_2 process emissions from soda ash manufacturing, reported for each manufacturing line.

• CO_2 combustion emissions from each soda ash manufacturing line.

• N_2O and CH_4 emissions from fuel combustion at each soda ash manufacturing line under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources) using the methodologies in subpart C.

• CO_2, N_2O, and CH_4 emissions from each stationary combustion unit other than soda ash manufacturing lines under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

In addition, report GHG emissions for any other source categories at the facility for which calculation methods are provided in other subparts of the rule, as applicable.

GHG Emissions Calculation and Monitoring. For CO_2 emissions from soda ash manufacturing lines, reporters must select one of the following methods, as appropriate:

• For each soda ash manufacturing line with certain types of CEMS in place, reporters must use the CEMS and follow the Tier 4 methodology (in 40 CFR part 98, subpart C) to report under the Soda Ash Manufacturing subpart (40 CFR part 98, subpart CC) combined process and combustion CO_2 emissions.

• For other soda ash manufacturing lines, reporters can elect to either (1) install and operate a CEMS and follow Tier 4 methodology to measure and report combined process and combustion CO_2 emissions or (2) calculate CO_2 process emissions using the procedures specified in 40 CFR part 98, subpart CC and summarized below.

• If using approach 2, calculate process CO_2 emissions using one of three alternative methods, as appropriate for each manufacturing line:

—The trona input method calculates the calcination emissions using: Monthly mass of trona input (required to be measured), the average monthly mass-fraction of inorganic carbon in the trona (required to be measured weekly), and the ratio of CO_2 emitted for each ton of trona consumed (a default value is provided).

—The soda ash output method calculates the calcination emissions using: Monthly mass of soda ash produced (required to be measured), the monthly average mass-fraction of inorganic carbon in the soda ash (required to be measured weekly), and the ratio of CO_2 emitted for each ton of soda ash produced (a default value is provided).

—The site-specific emission factor method calculates emissions from production of soda ash using liquid alkaline feedstock through an annual performance test using: The average process vent flow rate from the mine water stripper/evaporator for each manufacturing line, direct measurements of hourly CO_2 concentration, the hourly stack gas volumetric flow rate, the annual process vent flow rate from mine water stripper/evaporator, and annual operating hours.

—Report process CO_2 emissions from each soda ash manufacturing line under 40 CFR part 98, subpart CC (Soda Ash Manufacturing), and report combustion CO_2 emissions from each calciner (kiln) in each manufacturing line under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart CC.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart CC.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart CC: Soda Ash Manufacturing.''

• A site-specific emission factor method has been added for production of soda ash using liquid alkaline feedstock or mine water. This method was not included in the proposed rule.

• The frequency of inorganic carbon content determination of either trona or soda ash has been revised from daily to monthly based on a weekly composite.

• Procedures were added to 40 CFR 98.295 for estimating missing data for monthly values of inorganic carbon content of trona and monthly values of trona consumption or soda ash production. We also added missing data procedures for parameters specific to calculating emissions from soda ash produced from liquid alkaline feedstock (i.e. site-specific emission factor method).

• 40 CFR 98.296 was reorganized and updated to improve the emissions verification process. Some data elements were moved from 40 CFR 98.297 to 40 CFR 98.296, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.293 were added to 40 CFR 98.296 for clarity.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Two sets of comments on soda ash manufacturing were received covering several topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart CC: Soda Ash Manufacturing.''

Method for Calculating GHG Emissions

Comment: Both commenters noted that facilities produced soda ash using alternative methods to calcining trona or other carbonate containing minerals. Facilities also produce soda ash from mine water, a liquid alkaline feedstock; this is a ''process'' emissive production process, but was not addressed in the proposal. The methods in the proposal did not include methods appropriate for calculating process CO_2 from the liquid alkaline feedstock production process. One commenter using this production method recommended that the appropriate method for calculating emissions from this process would be an annual performance test and described the appropriate parameters that would be measured during the annual performance test to establish an emission factor for calculating annual emissions based on concentration of the CO_2 in the evaporated stripped mine water and the annual flow from the mine water stripper/evaporator.

Response: We agree that the final rule should address process CO_2 emissions generated from this relatively new alternative production process which produces soda ash from liquid alkaline feedstock or mine water. From additional information provided by the commenter, process CO_2 emissions from this production method are likely to be significant and exceed 25,000 metric tons CO_2e. This process is currently used by a single company, but could become more widespread within the industry in the future as it makes more efficient use of raw materials previously not used. We have updated all sections of 40 CFR part 98, subpart CC for calculating, monitoring and QA/QC, and reporting of process CO_2 emissions specific to production of soda ash from liquid alkaline feedstock or minewater. We added procedures for developing site-specific emission factor based on an annual performance test consistent with the recommendations provided by the commenter.

Comment: One commenter noted that using the total alkalinity of either trona or soda ash as prescribed in Equations CC–2 and CC–3 is inappropriate given that the ratio of carbon dioxide to carbon is a factor in the equations. The equations' results artificially inflated the CO_2 level by 3.67 times the actual amount.

Response: Upon further review, we agree with the commenter's analysis that the ratio 44/12 will overestimate emissions and have removed this fraction, which is the ratio of carbon dioxide to carbon, from Equations CC–2 and CC–3. Equations CC–2 and CC–3 provide results directly for CO_2 therefore it is not necessary to use a conversion factor to convert the carbon to carbon dioxide.

Comment: One commenter noted that Equation CC–3 does not address plant inefficiency specific to each manufacturing line. The commenter suggested that an efficiency factor should be added to Equations CC–3 to account for these inefficiencies.

Response: The commenter has not suggested an efficiency factor or otherwise provided data with enough specificity to modify the equations and modify the calculation methods as suggested; therefore, we have decided not to add efficiency factors to Equations CC–3.

EPA needs more information to effectively evaluate this comment and update the equations noted, if appropriate. Efficiency factors can relate to a number of factors including combustion and also kiln conditions, which may vary. We need more information to understand how this factor would be derived for each kiln or manufacturing line. The comment was specific to CC–3, and we suggest the use of Equation CC–2 as an alternative calculation method.

Monitoring and QA/QC Requirements

Comment: One commenter stated that daily sampling of inorganic carbon content of each manufacturing line is an unnecessary and potentially extremely costly requirement. They suggested that instead of daily testing, testing should be completed as a weekly composite analysis which would then be used in calculating the monthly average.

Response: We concur that testing of the inorganic carbon content can be done on a weekly schedule and used to calculate a monthly composite without significant loss in accuracy. The weekly composite would still be based on several daily tests. We have updated the monitoring and QA/QC requirements accordingly in the rule under 40 CFR 98.294.

Comment: One commenter stated that the prescribed ASTM method, ASTM E359–00(2005), for determining the inorganic carbon content of trona or soda ash describes a manual titration method using a methyl orange endpoint. They stated that procedures that use autotitrators with fixed endpoint titration are commonly used in the soda ash manufacturing industry and should be allowed as an acceptable equivalent alternative.

Response: We agree that methods using autotitration to determine inorganic carbon content of trona or soda ash expressed as total alkalinity are acceptable equivalent methods for determining the inorganic carbon content of trona or soda ash. We understand that manual titration offers good levels of accuracy but are labor and time intensive. From our understanding, autotitration methods provide comparable or improved levels of accuracy and are less labor and time intensive by ''automating'' the analysis process. Autotitration methods could provide more consistency in results across the industry. We have updated the procedures in 40 CFR 98.294 for monitoring and QA/QC in the rule to allow for such comparable methods.

DD. Sulfur Hexafluoride (SF_6) From Electrical Equipment

At this time EPA is not going final with the electrical equipment subpart. As we consider next steps, we will be reviewing the public comments and the relevant information.

Based on careful review of comments received on the preamble, rule, and TSDs under 40 CFR part 98, subpart DD, EPA will perform additional analysis and evaluate a range of data collection procedures and methodologies. EPA's goal is to optimize methods of data collection to ensure data accuracy while considering industry burden. In addition, EPA will further evaluate the scope of coverage of electric power systems and the reporting boundaries in other subparts.

EE. Titanium Dioxide Production

1. Summary of the Final Rule

Source Category Definition. The titanium dioxide production source category consists of any facility that uses the chloride process to produce titanium dioxide.

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. For titanium dioxide production, report CO_2 process emissions from each chloride process line.

In addition, report GHG emissions for other source categories for which calculation methods are provided in the rule, as applicable. For example, facilities must report CO_2, N_2O, and CH_4 emissions from each stationary combustion unit on site under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

GHG Emissions Calculation and Monitoring. Reporters must calculate CO_2 process emissions using one of two methods, as appropriate:

- Most reporters can elect to calculate and report process CO_2 emissions from titanium dioxide process lines by either (1) installing and operating CEMS and following the Tier 4 methodology (in 40 CFR part 98, subpart C) or (2) using the calculation procedures specified below.
- However, if process CO_2 emissions from titanium dioxide production are emitted through the same stack as a combustion unit or process equipment that uses a CEMS and follows Tier 4 methodology to report CO_2 emissions, then the reporter must use the CEMS to measure and report combined CO_2 emissions from that stack instead of using the calculation procedures described below.
- If using approach #2, calculate the process CO_2 emissions using the equation provided 40 CFR part 98, subpart EE and monthly determination of the mass and carbon content of calcined petroleum coke consumed in each line and all lines combined. Determine petroleum coke consumption by either direct measurement or purchase records. Determine carbon content of petroleum coke using supplier data or measurement using appropriate test methods. If applicable, also determine the quantity of carbon containing waste generated and its carbon contents using direct measurement.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart EE.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart EE.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart EE: Titanium Dioxide Production.''

- Requirements were added for reporting of carbon-containing waste generated from less than 100 percent oxidation of coke during the titanium production process. 40 CFR 98.316

allows for reporting of quantity of carbon-containing waste generated and associated carbon contents.

- Missing data procedures were added under 40 CFR 98.315 for monthly parameters used to calculate emissions, including mass of calcined petroleum coke, mass of carbon-containing waste, and carbon contents of calcined petroleum coke.
- 40 CFR 98.316 was reorganized and updated to improve the emissions verification process. Some data elements were moved from 40 CFR 98.317 to 40 CFR 98.316, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.313 were added to 40 CFR 98.316 for clarity.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. We received three sets of comments on titanium dioxide production covering several topics. Several of these comments were directed at the requirements for General Stationary Fuel Combustion Sources in subpart C, and responses to those comments are provided in the preamble section dealing with that source category. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart EE: Titanium Dioxide Production.''

Method for Calculating GHG Emissions

Comment: One commenter noted that the carbon oxidation factor for calcined petroleum coke is not always 100 percent. They point out that the calcined petroleum coke comes with impurities, and a certain amount of the calcined coke is returned to the ground as landfill along with components such as the un-converted TiO_2. Thus, they suggest that EPA should revise the carbon oxidation factor to allow facilities to use the most appropriate factor for their process, with supporting documentation of its derivation available for EPA review as needed.

Response: EPA has considered the comment but maintains the assumption of 100 percent oxidation across all sectors in the final rule. Data reporting requirements have been added to 40 CFR 98.316 to collect information on the quantity of carbon-containing waste generated that is landfilled and its carbon contents which are not emitted. This information will help inform future methods for calculating process emissions from titanium dioxide production (e.g., how to address oxidation rates). EPA interpreted that this comment may also be applicable to carbon content of calcined petroleum coke. EPA agrees that carbon content may not always be 100 percent and therefore has revised the rule to allow facilities to use supplier data or determine carbon contents using appropriate test methods as part of calculating emissions in 40 CFR 98.313.

Procedures for Estimating Missing Data

Comment: Two commenters noted there can be numerous reasons data may not be available, on time, or in the format EPA requires. In cases where a required record is found to be missing or determined to be incorrect, the commenters requested that EPA should provide a procedure for estimating missing data.

Response: We concur that there may be circumstances where data on carbon contents of coke and petroleum coke consumption may be missing. Records could be misplaced or lost. Thus, we have revised the rule and added specific procedures for estimating missing data in 40 CFR 98.315. These procedures are consistent with those allowed across the rule for similar parameters. For example, if a facility is missing data on carbon contents of petroleum coke we allow facilities to allow sources to substitute the missing data with another quality assured parameter, such as the arithmetic average of the carbon contents from the month immediately preceding and the month immediately following the missing data incident.

Data Reporting Requirements

Comment: All commenters noted they are concerned that the level of information to be reported, which is considered available for public distribution, could put the domestic TiO_2 producers at a disadvantage relative to international producers. The commenters do not believe that CBI provisions briefly outlined in the preamble are adequate to safeguard the proprietary technical and financial positions of titanium dioxide production facilities. The annual production of titanium dioxide, annual amount of petroleum coke consumed, and annual operating hours are considered CBI and are unnecessary to carry out the purposes of this proposed regulation. This data should only be available onsite or offsite (e.g., a centralized location), or as requested for security cleared EPA personnel and their security cleared contractors where a need is demonstrated for the purposes of this inventory.

Response: EPA reviewed CBI comments received across the rule (both general and subpart-specific comments) and our response is discussed in Section II.R of this preamble and in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues.''

In addition, see the Section II.N of this preamble for the response on the emissions verification approach. The amount of petroleum coke consumed is necessary to calculate annual process CO_2 emissions. Production capacity and annual production of titanium dioxide are required for EPA to verify annual CO_2 process emissions. These parameters help EPA to determine whether reported emissions are within a reasonable range. EPA concurs that data on operating hours can be retained as a record and does not need to be reported to EPA. It is not a parameter used in calculating process CO_2 emissions. However, operating hours would help to verify any anomalies in reported emissions or supporting parameters related to temporary closures for repairs or maintenance. This data has been moved to recordkeeping requirements in 40 CFR 98.317.

FF. Underground Coal Mines

At this time, EPA is not finalizing the Underground Coal Mines Subpart (40 CFR part 98, subpart FF). As EPA considers next steps, we will be reviewing the public comments on the proposal preamble, rule and TSDs for proposed 40 CFR 98 Subpart FF and other relevant information. EPA will perform additional analysis and consider alternatives to the monitoring requirements.

GG. Zinc Production

1. Summary of the Final Rule

Source Category Definition. Zinc production facilities consist of zinc smelters and secondary zinc recycling facilities.

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. For zinc production, report the following:

- CO_2 process emissions from each Waelz kiln and electrothermic furnace used for zinc production.
- CO_2, N_2O, and CH_4 combustion emissions from each Waelz kiln and each other stationary combustion unit on site under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

In addition, report GHG emissions for other source categories at the facility for which calculation methods are provided in the rule, as applicable.

GHG Emissions Calculation and Monitoring. Facilities must calculate CO_2 process emissions using one of two methods, as appropriate:

• Most reporters can elect to calculate and report process CO_2 emissions from each Waelz kiln and electrothermic furnace by either (1) installing and operating CEMS and following the Tier 4 methodology (in 40 CFR part 98, subpart C) or (2) using the calculation procedures specified in the rule.

• However, if process CO_2 emissions from a Waelz kiln or electrothermic furnace are emitted through the same stack as a combustion unit or process equipment that uses a CEMS and follows Tier 4 methodology to report CO_2 emissions, then the CEMS must be used to measure and report combined CO_2 emissions from that stack, instead of the calculation procedure described below.

• If using approach #2, calculate process CO_2 emissions by determining on an annual basis the total mass (metric tons) of carbon-containing input materials (i.e., zinc-bearing material, flux, electrodes, and any other carbonaceous materials) introduced into each kiln and furnace and the carbon content of each material. Determine carbon content annually either by using supplier data, or by direct measurement using appropriate test methods.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart GG.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart GG.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these changes can be found below.

• The carbon input method was revised to require an annual analysis of all process inputs and outputs for carbon content rather than monthly sampling and monthly analysis.

• A *de minimis* was added to exclude accounting for carbon-containing materials contributing less than one percent of the total carbon into Waelz kiln or electrothermic furnaces. These materials do not need to be included in carbon mass balance calculations.

• 40 CFR 98.336 was reorganized and updated to improve the emissions verification process. Some data elements were moved from 40 CFR 98.337 to 40 CFR 98.336, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.333 were added to 40 CFR 98.336 for clarity.

3. Summary of Comments and Responses

No comments specific to regulation of the zinc production sector were received. We revised the frequency of sampling and analysis of carbon contents for carbon containing input materials from monthly to annual consistent with revisions made in response to comments for similar production processes (e.g., emissions from metal production, see the preamble Section III.Q for iron and steel for specific responses to comments). These revisions reduce the reporting burden for zinc production facilities. We understand that the carbon content of material inputs does not vary widely at a given facility for the significant process inputs that contain carbon, and we continue to account for variations due to changes in production rate, which is likely a more significant source of variability.

HH. Municipal Solid Waste Landfills

1. Summary of the Final Rule

Source Category Definition. This source category consists of municipal solid waste (MSW) landfills that accepted waste on or after January 1, 1980. The source category includes the MSW landfill, landfill gas collection systems, and landfill gas destruction devices (including flares) at the landfill.

This source category does not include hazardous waste, construction and demolition, or industrial landfills.

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

GHGs to Report. For MSW landfills, report the following:

• Annual CH_4 generation and CH_4 emissions from the landfill.

• Annual CH_4 destruction (for landfills with gas collection and control systems).

• Annual CO_2, CH_4, and N_2O emissions from stationary fuel combustion devices under 40 CFR part 98, subpart C (General Stationary Combustion Sources).

GHG Emissions Calculation and Monitoring. All facilities must calculate modeled annual CH_4 generation based on:

• Measured or estimated values of historic annual waste disposal quantities; and

• Appropriate values for model inputs (i.e., degradable organic carbon fraction in the waste, CH_4 generation rate constant). Default parameter values are specified for bulk municipal waste and individual waste categories.

Facilities that do not collect and destroy landfill gas must adjust the modeled annual CH_4 generation to account for soil oxidation (CH_4 that is converted to CO_2 as it passes through the landfill cover before being emitted) using a default soil oxidation factor. The resulting value must be reported and represents both CH_4 generation and CH_4 emissions.

Facilities that collect and control landfill gas must calculate the annual quantity of CH_4 recovered and destroyed based on either continuous or weekly monitoring of landfill gas flow rate, CH_4 concentration, temperature, and pressure of the collected gas prior to the destruction device.

Those facilities that collect and control landfill gas must then calculate CH_4 emissions in two ways and report both results. Emissions must be calculated by:

1. Subtracting the measured amount of CH_4 recovered from the modeled annual CH_4 generation (with adjustments for soil oxidation using the default value and destruction efficiency of the destruction device) using the equations provided; and

2. Applying a gas collection efficiency to the measured amount of CH_4 recovered to calculate CH_4 generation, then subtracting the measured amount of CH_4 recovered (with adjustments for soil oxidation using the default value and destruction efficiency of the destruction device) using the equations provided. Default collection efficiencies are specified, based on cover material and other factors.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart HH.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart HH.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be founds below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart HH: Landfills.''

- Industrial landfills were removed from the applicability provisions of 40 CFR part 98, subpart HH. The applicability provisions were also modified to exempt landfills that did not accept any waste after January 1, 1980.
- Additional methods for estimating quantities of waste for prior (historic) years are provided.
- The requirement to continuously monitor CH_4 composition in the flare gas was removed. If a continuous monitoring system is in place, that data must be used, but weekly sampling of the gas is allowed if such a continuous system is not in place.
- Direct flame ionization methods were added to the rule as an alternative to the gas chromatographic methods for determining methane concentrations. To use a direct flame ionization method, a correction factor must be determined at least once each reporting year and applied to adjust the analyzer's total gaseous organic concentration to an unbiased methane concentration.
- More detailed default values are provided for landfill gas collection efficiencies based on cover material and other factors.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on landfills were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart HH: Landfills.''

Definition of Source Category

Comment: Several commenters stated that EPA should limit the applicability of the industrial landfills to landfills located at food processing, pulp and paper, and ethanol production facilities (some also listed petroleum refineries) because these are the only industries for which landfills were specifically called out. Several commenters noted that impacts were only estimated for pulp and paper and food processing landfills, so EPA should limit the rule to those industries or correct the cost analysis to reflect the true burden of the rule on industrial landfills. Several commenters noted that the reporting requirements seemed tailored for MSW landfills and were generally inappropriate for industrial landfills (truck scales, etc.). One commenter also noted that, if reporting of GHG emissions from industrial landfills is not limited to the food processing, pulp and paper, and ethanol production facilities, then EPA should amend Table HH–1 of 40 CFR part 98, subpart HH and provide specific factors that are relevant to the regulated industry. Several commenters requested that EPA specifically exempt inorganic chemical manufacturing and mining landfills because they do not contain organic waste; other commenters suggested EPA delete requirements for landfills in 40 CFR part 98, subpart Y because landfills are insignificant compared to other sources at a petroleum refinery.

On the other hand, one commenter suggested that EPA may be overlooking an important source of methane emissions by excluding construction and demolition landfills as it seems possible that these landfills receive organic materials such as wood or yard waste that could degrade in an anaerobic environment. This commenter requested EPA provide information on the waste composition of construction and demolition landfills to explain more fully the basis for its decision to categorically exempt these sources from GHG reporting requirements.

Response: At this time, EPA is not going final with the industrial landfills proposed requirements of this subpart. In response to the proposal, EPA received numerous detailed public comments on the preamble, rule and TSDs under 40 CFR part 98, subpart HH. Comments addressed the appropriateness, coverage, and methodology for addressing GHG emissions from industrial landfills. In particular, commenters questioned which industrial landfills should be covered by the rule and the need for industry specific factors and methodologies for calculating and reporting emissions. As EPA considers next steps, we will be reviewing the comments and other relevant information and will perform additional analysis and consider alternatives to the proposed monitoring and reporting requirements for industrial landfills.

With regard to construction and demolition landfills, we note that the IPCC 2006 Guidelines for National Greenhouse Gas Inventories estimates that construction and demolition waste has a degradable organic content (DOC) of 0.04 kg/kg waste (*see* Table 2.5 in Volume 5: Waste), and most of this organic matter is expected to be wood, with slow degradation rates ($k=0.02\ yr^{-1}$). Based on the anticipated properties of construction and demolition wastes, we anticipated that methane generation at dedicated construction and demolition debris landfills would be small compared to MSW landfills. We will further review these assumptions as we review comments on industrial landfills.

Comment: Several commenters stated that the reporting requirements for closed landfills are burdensome, and the rule should be limited to reporting for active landfills. Information on waste disposal quantities and waste composition data are usually not available for closed MSW facilities. Thus, it is impossible to retain or provide the agency with such records for many old landfill sites. Several commenters suggested that EPA should provide additional guidance and screening tools to identify landfills likely to be below the threshold. The commenters noted that small and closed landfills have to collect all of the data needed to report their emissions in order to determine if they are above the reporting threshold.

Response: Closed MSW landfills account for approximately half of the nationwide methane emissions from MSW landfills. This is because landfills can continue to emit for decades after they are closed and because these landfills are older, and less likely to have been required to add landfill gas collection systems. However, we do agree that we can remove reporting requirements for a subset of closed landfills to lessen the burden on long-closed landfill facilities. We evaluated the various landfill characteristics and identified that a 30-year waste-in-place (i.e., the total quantity of waste added to the landfill in the past 30 years) provided the best correlation of the data to sites that account for the majority of the contribution to the nationwide GHG emissions from landfills (see memorandum entitled ''Correlations with Landfill Methane Generation and Actual Emissions'' in the docket EPA–HQ–OAR–2008–0508–2165). Providing an applicability date for closed landfills is essential to minimize the burden associated with obtaining data on old landfills that provide only a small contribution to the nationwide GHG emissions for landfills, and landfills closed prior to 1980 would not be relevant for the purposes of policy analyses. Therefore, the final rule excludes MSW landfills that have not accepted waste since January 1, 1980. We have also expanded and clarified options for projecting waste disposal quantities that will help ease the burden associated with calculating emissions from landfills that have closed after 1980. EPA remains committed to providing additional outreach materials, guidelines, and screening tools to help potential reporters determine whether the reporting rule applies to their landfill.

Method for Calculating GHG Emissions

Comment: Several commenters requested additional guidance on how to determine waste disposal rates for years prior to the first reporting year. One commenter noted that the population method provided in the rule was difficult for many landfills because of contract carriers that may haul waste to different landfills in different years, so that the population served by a landfill can be variable. Several commenters noted that the data needed to estimate waste disposal rates for past years was especially challenging for closed landfills and requested guidance on how to comply with the rule if the necessary data do not exist.

Response: EPA acknowledges that the single proposed method of estimating past year disposal rates is limiting and may not provide the most accurate projection of waste disposal rates in all cases. We have provided a number of alternative approaches that could be used to estimate annual waste acceptance rates. These include using the current year's annual waste acceptance rate for all past years of operation (for active landfills) and using the landfill capacity and the operating life of the landfill to calculate an average annual acceptance rate (for active and closed landfills). These methods provide a reasonable estimate of historic disposal quantities based on readily available information, even for older landfills. Furthermore, these alternative methods may be just as appropriate or more appropriate for MSW landfills that do not serve a fixed population area.

Comment: A few commenters noted that the Solid Waste Industry for Climate Solution (SWICS) has developed protocols for calculating GHG emissions from landfills [see paper titled, Current MSW Industry Position and State-of-the-Practice on LFG Collection Efficiency, Methane Oxidation, and Carbon Sequestration in Landfills (July 2007)]. The commenters requested that the SWICS recommended defaults for gas recovery system efficiency, soil oxidation, and flare combustion efficiency be provided in the rule. They also stated that an accurate inventory should account for carbon sequestered in the landfill.

Response: We again reviewed the SWICS methods in light of these comments. We agree that the SWICS default recommendations for gas recovery system efficiency (which vary from 60 to 95 percent for different types of soil covers) could provide more refined data than using the default values provided in the rule. Therefore, we have included these cover-specific gas recovery efficiencies (commensurate with the SWICS Protocol) as an alternative to the 75 percent default value for collection efficiency. We have also reviewed the SWICS protocol for soil oxidation, which provides suggested oxidation factors ranging from 0.22 to 0.55 depending on the soil cover type. We have several concerns with these factors. First, the values were calculated using arithmetic means which appear to be biased high due to a few high oxidation factors; the median values were generally significantly lower than the average values suggested. Second, the recommended values included laboratory test values, which always yielded higher oxidation fractions. The percent of methane oxidized at the landfill surface is highly dependent on the velocity of gas flow. While areas of low flow are expected to have significant oxidation, areas of high flow will have little to no oxidation. Landfill gas will generally flow to the surface in fissures and channels that offer the least resistance to flow. Consequently, a significant portion of the landfill gas is likely to exit the landfill in a limited number of areas under much higher flow rates than other locations. These high volume flows will not have significant oxidation. Consequently, field test data tend to show lower oxidation factors than laboratory tests where flow is more uniform. Data for five field studies for clay covers (the predominant soil cover type used in the U.S.) were included in the SWICS report. Four of the five field studies had oxidation factors ranging from 0.08 to 0.21, and the median of all five field studies was 0.14. These data appear to support the default 0.10 oxidation factor as provided in the final rule more than they do the 0.22 oxidation factor suggested by SWICS. We will continue to assess the available data to improve soil oxidation estimates; however, we maintain that the use of the 10 percent default rate is appropriate for this final rule, and clarify that the site-specific oxidation factors (based on the SWICS method or other method) are not to be used. We also find that the SWICS Protocol recommended flare efficiency of 99.996 percent appears unreasonably high. The combustion efficiency of flares is very difficult to assess and may be affected by wind speed and other variables that are not under the direct control of the landfill owner and operator. Consequently, we retained the proposed flare efficiency default. Finally, with respect to the suggested sequestration factors, since collecting data on carbon sequestration is not the purpose of this rule, we do not require facilities to calculate or report carbon storage in landfills.

Monitoring and QA/QC Requirements

Comment: Several commenters stated that EPA's proposal to require landfills with gas collection systems to continuously measure the methane flow and concentration at the flare or energy device is financially burdensome. According to commenters, the capital costs as well as operation and maintenance costs of a continuous composition analyzer are prohibitive for many facilities, and EPA underestimated the number of facilities that would have to install the required monitors. The commenters also stated that the composition of landfill gas is not highly variable, so less frequent monitoring is justified. One commenter noted that the standard operating procedure at many landfills with gas collection systems is to collect monthly CH_4, flow, and concentration data at the flare. Another commenter recommended that MSW landfills be allowed to calculate quarterly, by means of engineering formulae and/or modeling, the amount of methane present at the flare or energy device. The commenter further noted that, in many cases, it is not practical or even possible for the MSW facility to measure the amount of methane or even landfill gas at the energy device because this device is not owned, operated, or controlled by the facility. Several commenters also requested that EPA allow direct flame ionization analyzers in addition to the gas chromatography methods provided in the proposed rule.

On the other hand, several commenters suggested that EPA should allow, require, or otherwise move towards direct measurement methodologies for characterizing landfill emissions.

Response: Methane composition of landfill gas can be expected to vary based on extreme barometric changes, rainfall event, etc. We expect diurnal variations as well (although not to the same extent as seasonal variations). We also expect variations if the gas collection system has a variable speed fan and the fan speed is adjusted. The commenters provided no data to support the claim that the anticipated fluctuations are not significant enough to warrant continuous monitoring. At proposal, we required continuous flow and composition monitors to improve the accuracy of the emissions estimate. However, after additional uncertainty analysis, we determined that the cost of continuous monitoring systems is not justified in relation to the relatively small improvement in certainty over somewhat less frequent monitoring, i.e. weekly. We do require landfill gas collection systems already equipped with continuous monitoring systems to determine daily average flow and concentrations and to use these data in their gas recovery calculations. For collection systems that do not have continuous gas monitors, weekly sampling is required. Weekly monitoring provides an adequate number of samples to evaluate the variability and uncertainty associated with methane generation. We did not select monthly monitoring because monthly monitoring would result in greater uncertainty and would not significantly reduce the costs compared to weekly monitoring.

We did provide for direct flame ionization analyzers to be used as an alternative to the gas chromatography methods provided in the proposed rule. This alternative reduces the burden on landfills that do not have existing gas chromatography equipment. However, direct flame ionization analyzers will measure both methane and non-methane organic compounds and, as such, will tend to overstate the methane concentration in the landfill gas and provide a high bias to the amount of methane recovered. To eliminate this bias, we also required a correction factor that must be determined at least annually, to arrive at the ratio of the methane concentration to the direct flame ionization analyzer response (calibrated with methane). Including this alternative method with the correction factor reduces the burden on landfills, but still ensures that the calculated methane recovery quantities are unbiased and comparable to the recovery quantities calculated when gas chromatographic methods are used to speciate methane specifically.

With respect to direct measurement methods, we find that direct soil measurements have high uncertainties due to heterogeneity of the landfill and cover soils and are, therefore, less desirable than the methods provided in the rule (cost more and have higher uncertainty). Optical sensing methods, while potentially more accurate, are very expensive. If measurements were done for only a one-time performance test, the measured emissions would have rather high uncertainties due to variations in temperature and atmospheric pressure. If the measurements were conducted more often, they would be prohibitively expensive. At this time, we cannot justify requiring these types of monitoring systems for this rule. Furthermore, we find that the monitoring requirements in the final rule provide for accurate emission estimates at a reasonable cost burden to reporters.

II. Wastewater Treatment

At this time, EPA is not going final with the wastewater treatment subpart (40 CFR part 98, subpart II). As EPA considers next steps, we will be reviewing the public comments and other relevant information. Please note, as originally proposed for this rule, centralized domestic wastewater treatment plants continue to be excluded.

The Agency received a number of comments regarding the applicability of this subpart as well as clarification of the definition of anaerobic wastewater treatment processes. In addition, commenters requested that EPA consider a *de minimus* exemption for emissions from wastewater treatment. The Agency also received a number of comments requesting redefinition of the monitoring requirements for this subpart.

Based on careful review of comments received on the preamble, rule and TSDs under proposed 40 CFR part 98, subpart II, EPA will consider alternatives to data collection procedures and methodologies and examine additional study results that have been released since the proposal was issued. Specifically, EPA will consider requirements for the location of meters for taking flow measurements, the frequency of flow and chemical oxygen demand (COD) measurements taken, as well as the potential use of alternate parameters, such as BOD. EPA will also consider the inclusion of indirect or non-methane volatile organic compound emissions. Lastly, EPA will consider the acceptable methods for estimating missing data. EPA will consider optimal methods of data collection in order to maximize data accuracy, while considering industry burden.

JJ. Manure Management

1. Summary of the Final Rule

Source Category Definition. A livestock facility that emits 25,000 metric tons CO_2e or more per year from manure management systems must report. A facility with an average annual animal population below those listed in Table JJ–1 of 40 CFR part 98, subpart JJ, does not need to calculate emissions or report. A facility with an average annual animal population that exceeds those listed in Table JJ–1 should conduct a more thorough analysis to determine applicability. Average annual animal populations for static populations (e.g., dairy cows, breeding swine, layers) are estimated by performing an animal inventory or review of facility records. Average annual animal populations for growing populations (meat animals such as beef and veal cattle, market swine, broilers, and turkeys) are estimated using the average number of days each animal is kept at the facility and the number of animals produced annually. The rule also contains procedures for facilities with more than one animal group present (e.g., swine and poultry) to determine if they must report.

A manure management system stabilizes or stores livestock manure, or does both, in one or more of the following system components:

- Uncovered anaerobic lagoons.
- Liquid/slurry systems with and without crust covers (including but not limited to ponds and tanks).
- Storage pits.
- Digesters, including covered anaerobic lagoons.
- Solid manure storage.
- Drylots, including feedlots.
- High-rise houses for poultry production (poultry without litter).
- Poultry production with litter.
- Deep bedding systems for cattle and swine.
- Manure composting.
- Aerobic treatment.

GHG emissions from sources at livestock facilities unrelated to the stabilization and/or storage of manure are not covered under this rule and are not reported. Sources considered to be unrelated to the stabilization and/or storage of manure include daily spread or pasture/range/paddock systems or land application activities or other methods of manure utilization not listed above. In addition, manure management activities located off site from a livestock operation are not included in this rule. These off site activities include but are not limited to off site land application of manure, other off site methods of manure utilization, or off site manure composting operations.

Facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble must report GHG emissions.

GHGs to Report. For all livestock facilities with a manure management system that meets or exceeds the reporting threshold, the facility must report aggregate CH_4 and N_2O emissions from the system components listed above. For those manure management systems that include digesters, CH_4 generated and destroyed, as well as any CH_4 leakage, at the digester must also be reported.

A facility that is subject to this rule only because of emissions from manure management systems is not required to report emissions under 40 CFR part 98 subparts C through PP other than subpart JJ.

GHG Emissions Calculation and Monitoring. Detailed methods for calculating GHG emissions are included in the rule and are briefly described below. For each manure management system component other than digesters, facilities must calculate emissions using the following inputs and data:

- Type of system component.
- Average annual animal population (by animal type) contributing manure to the manure management system component.
- Typical animal mass (for each animal type).
- Fraction of manure by weight for each animal type managed in each system component (assumed to be equal to the fraction of volatile solids/nitrogen handled in each system component).
- Volatile solids excretion rates provided in look-up tables for the animal populations contributing manure to the manure management system component.
- Maximum CH_4-producing potential of the managed manure and CH_4 conversion factors provided in look-up tables for the animal populations contributing manure to the manure management system component.
- Methane conversion factor used (for each manure management system component).
- Nitrogen excretion rates (by animal type) using values provided in look-up tables for the animal populations contributing manure to the manure management system component.
- N_2O emission factors (by animal type) provided in look-up tables for the animal populations contributing manure to the manure management system component.

For anaerobic digesters, facilities must calculate CH_4 emissions and the annual mass of CH_4 generated and destroyed based on the following inputs and data:

- Continuous monitoring of CH_4 concentration, flow rate, temperature, and pressure of the digester gas.
- CH_4 destruction efficiency of the destruction device and fugitive (leakage) emissions.
- The CH_4 collection efficiency(ies) used (for each digester).

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, facilities must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart JJ.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, facilities must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart JJ.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified below. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart JJ: Manure Management.''

- To assist facilities in determining if they are subject to this rule, a table has been provided that presents average annual animal population values for specific livestock operations (i.e., beef, dairy, swine, and poultry). Facilities that have average annual animal population values below those shown in the table will not be required to report or complete the calculations to determine whether they need to report.
- Since proposal, the requirements for monthly manure sampling to determine volatile solids (VS) and nitrogen (N) content have been removed. Instead of obtaining VS and N content from manure sampling, facilities must use default VS and N excretion values as provided by EPA in look up tables. The default VS and N excretion values are consistent with the 1990–2008 U.S. GHG inventory for manure management and enteric fermentation. For beef and dairy cows, heifers, and steers, VS and N excretion rates were calculated using the IPCC Tier II methodology, based on the relationship between animal performance characteristics such as diet, lactation, and weight gain and energy utilization. In response to comments, EPA used the most up-to-date information on U.S. animal diets to calculate these excretion rates. For other animal groups, reference values from ASAE and USDA are used.
- EPA has also adjusted the calculations for CH_4 and N_2O emissions from manure management systems to account for volatile solids and nitrogen removal through solid separation. If solid separation occurs prior to the manure management system component, facilities must use default removal efficiencies as provided by EPA in look up tables. The default values are consistent with those cited in the ''Development Document for the Final Revisions to the National Pollutant Discharge Elimination System Regulation and the Effluent Guidelines for Concentrated Animal Feeding Operations'' (EPA–821–R–03–001), published in December 2002.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on manure management were received covering numerous topics. Responses to significant comments received can be found in the comment response document for manure management in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart JJ: Manure Management.''

Comment: A number of commenters supported EPA's decision to include livestock facilities with manure management systems in the proposed rule. These commenters noted that the establishment of a mandatory GHG reporting rule is the next logical step in reducing and mitigating GHG emissions in the U.S., and that manure management is a significant source of GHG emissions in the U.S. that should be addressed.

However, other commenters stated that livestock facilities should not be required to report GHG emissions. These commenters noted that a small number of facilities would be covered by the proposed rule, and these facilities would represent a very small percentage of the total number of livestock facilities in the U.S. which would not provide a large enough set of data to help improve or reduce uncertainties associated with GHG inventories. Several of the commenters stated that manure management is not a major source of GHG emissions in the U.S., and the environmental benefits from the rule would be minimal compared to the effort required to report emissions.

Response: EPA disagrees that the manure management source category be excluded from this rule. Manure management has been determined to be a key source of GHG emissions in the U.S., based on the key source category methodology developed by the Intergovernmental Panel on Climate Change (IPCC). The IPCC identifies key sources as those sources that have significant impacts on the total emissions or emission trends in a country.

While livestock manure GHG emissions represent a relatively small fraction of the total U.S. GHG emissions, these emissions are large in absolute terms. According to the 2009 U.S. GHG Inventory, CH_4 emissions from manure management systems totaled 44 million metric tons CO_2e, and N_2O emissions were 14.7 million metric tons CO_2e in 2007; manure management systems account for 7.5 percent of total anthropogenic CH_4 emissions and 4.7 percent of N_2O emissions in the U.S.

In addition, the collection of facility level GHG emission data, including the type of manure management systems in operation and the number and types of animals serviced by those systems, will help to inform future climate change policy decisions. While the actual number of facilities reporting will be quite small in comparison to the total number of facilities in the U.S., the data gathered through this effort is valuable. For example, these data will help to improve the understanding of emission rates and actions that facilities take to reduce emissions and may improve the effectiveness and design of voluntary and/or mandatory programs to reduce emissions.

Comment: Multiple commenters stated that the monitoring requirements in the proposed rule would be too burdensome and expensive for industry to comply with. These commenters expressed concern that sampling manure for VS and N would require more time and effort and be more expensive than EPA estimated. Multiple commenters suggested that default values such as from the American Society of Agricultural and Biological Engineers (ASABE) be permitted for VS and N instead of measured values to eliminate some of the expense associated with the proposed rule.

In addition, a number of commenters noted that there were some methodological issues associated with the monitoring requirements for VS and N. Multiple commenters noted that the requirements for manure sampling should be clarified.

Response: EPA acknowledges these concerns and has removed the manure sampling requirements from the final rule. As discussed earlier, EPA used default values for VS and N excretion from USDA and ASAE for swine and poultry, and has calculated these rates for beef and dairy cows, heifers, and steers using the IPCC Tier II methodology, based on the relationship between animal performance characteristics such as diet, lactation, and weight gain and energy utilization. The use of these animal-specific default values for VS and N will greatly reduce the burden to comply with the reporting rule, while only minimally impacting the estimates of GHG emissions. The variation in sampling techniques from facility to facility when characterizing manure ''as excreted'' from the various animal populations on the facility (as would have been required by the proposal) would negate the benefit derived from this requirement. EPA considered designing a more complex and rigorous program to ensure consistency in the implementation of a manure sampling program and to ensure that manure samples represented ''as excreted'' manure (prior to any storage or treatment). However, after reviewing comments, we determined that the expected burden of such a program, in terms of time, effort, and expense, outweighed the merits at this time.

Comment: A number of commenters noted that calculation errors caused threshold head numbers to be overestimated, which caused the amount of emissions from these operations and the number of operations that would need to report to be underestimated.

Response: To estimate the number of facilities at each threshold, EPA first developed a number of model facilities to represent the manure management systems that are most common on large livestock operations and have the greatest potential to exceed the GHG reporting threshold. Next, EPA used the U.S. GHG inventory methodology for manure management to estimate the numbers of livestock that would need to be present to exceed the threshold for each model livestock operation type. Finally, EPA combined the numbers of livestock required on each model operation to meet the thresholds with U.S. Department of Agriculture (USDA) data on farm sizes to determine how many farms in the United States have the livestock populations required to meet the GHG thresholds for each model livestock operation.

Since proposal, EPA made revisions to the threshold analysis spreadsheet calculations based on information and data provided by commenters. EPA corrected conversion factors used in the nitrous oxide emission calculations, and corrected spreadsheet cell reference errors along with using updated VS and N values. EPA now estimates that there will be approximately 107 livestock facilities that will need to report under the rule.

Comment: Commenters also expressed concerns with the emission calculations. Multiple commenters noted that the maximum methane producing capacity (Bo) values used do not reflect variations in animal diet. Several commenters had concerns about the methodology used to estimate the methane conversion factors. In addition, some commenters suggested that other data sources should be considered, such as the ASABE manure standards.

Response: After a thorough review of available information, EPA has determined that the methodologies and data sources used to calculate emissions in this rule represent the best available methods and data. EPA reviewed many protocols and approaches prior to selecting the proposed methodology. EPA's selected methodology for reporting GHG emissions (methane and nitrous oxide) associated with manure management systems is based on EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks, as well as the IPCC Guidelines for National Greenhouse Gas Inventories. These methodologies rely on the use of activity data, such as the number of head of livestock, operational characteristics (e.g., physical and chemical characteristics of the manure, type of management system(s)), and climate data, to calculate GHG emissions associated with traditional manure management systems. In addition, the selected methodology for the reporting rule uses measured values for those manure management systems (e.g., anaerobic digesters) that collect and combust biogas.

EPA considered requiring direct measurement of GHG emissions from manure management systems, but rejected this approach due to the extreme expense and complexity of such a measurement program. EPA is promulgating an approach that allows the use of default factors, such as a system emission factor, for certain elements of the calculation, and encourages the use of some site-specific data. The cost of such an approach is significantly lower than a direct measurement program. In addition, this approach is consistent with the methods used in offset programs throughout the world, including the California Climate Action Registry's (CCAR) Manure

Management Project Reporting Protocol. For these offset programs, livestock operations are required to complete calculations that establish their ''baseline'' emissions (prior to the use of a biogas collection system). These baseline emission calculations use similar emissions calculations and default values as are in EPA's Reporting Rule.

The IPCC guidelines have been established by a recognized panel of experts and underwent significant peer review prior to their adoption. In addition, protocols for offset programs, such as CCAR, have gone through similar public review processes prior to their acceptance and use.

Comment: Multiple commenters have requested more detailed look up tables and a tool to provide more clarity on which facilities are required to report under the final rule.

Response: EPA agrees that additional tables and tools would facilitate compliance with the rule and ease the burden associated with reporting. In response to the comments, EPA has added a threshold table to the final rule (Table JJ–1) to help livestock facilities with manure management systems better determine if they might be subject to the requirements of the rule. EPA also intends to develop applicability tools that can assist facilities that could be covered by the rule, based on table JJ–1 in 450 CFR part 98, subpart JJ, in conducting a more detailed evaluation. These tools will include detailed look-up tables showing the estimated livestock head numbers that would be necessary in order to meet or exceed the threshold and a calculation tool to assist in performing the calculations in the proposed rule.

KK. Suppliers of Coal

At this time, EPA is not going final with a subpart for suppliers of coal. As EPA considers next steps, we will be reviewing the public comments and other relevant information.

The Agency received a number of lengthy, detailed comments regarding the coal suppliers subpart. Commenters generally opposed the proposed reporting requirements and raised multiple issues with EPA's legal authority for requiring coal suppliers to report CO_2 emissions. Several commenters stated that reporting by coal suppliers would represent a duplication of the reporting by coal users. For example, electric utilities and industrial plants, which consume the vast majority of coal supplied, are already required to report data on emissions based on their coal purchases. Commenters also stated that the reporting requirement would entail significant burden and capital costs to coal suppliers. In most cases, commenters provided alternative approaches to the reporting requirements proposed by EPA. For example, commenters suggested that EPA exempt from reporting coal mines that supply coal to mine-mouth power plants, modify the required coal weighing and sampling standards, and eliminate the required statistical correlation between HHV and carbon content.

Commenters raised other issues regarding the reporting of data such as concerns that coal suppliers and laboratories could not realistically purchase and install new coal testing and sampling equipment and provide training to meet the requirements of the proposed rule.

Based on careful review of comments received on the preamble, rule and TSDs under proposed 40 CFR part 98, subpart KK, EPA will perform additional analysis and consider alternatives to data collection procedures and methodologies. These alternatives will provide coverage of coal supplied, imported, or exported while concurrently taking into account industry burden.

LL. Suppliers of Coal-Based Liquid Fuels

1. Summary of the Final Rule

Source Category Definition. This source category consists of producers, importers, and exporters of products listed in Table MM–1 of 40 CFR part 98, subpart MM that are coal-based (coal-to-liquid products). A producer of coal-to-liquid products is any owner or operator who converts coal into liquid products (e.g., gasoline, diesel) using the Fischer-Tropsch or an alternative process.

Suppliers of coal-to-liquid products that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble must report GHG emissions.

GHGs to Report. Suppliers of coal-to-liquid products must report the CO_2 emissions that would result from the complete combustion or oxidation of the coal-to-liquid products.

Suppliers of coal-to-liquid products are not required to report data on emissions of other GHGs that would result from the complete combustion or oxidation of their products, such as CH_4 or N_2O.

GHG Emissions Calculation and Monitoring. For each type of coal-to-liquid product, suppliers must calculate CO_2 emissions that would result from the complete combustion or oxidation of the coal-to-liquid products by following the procedures in 40 CFR 98.393.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions that would result from the complete combustion or oxidation of their products. A list of the specific data to be reported for this source category is contained in 40 CFR 98.386.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions that would result from the complete combustion or oxidation of their products. A list of specific records that must be retained for this source category is included in 40 CFR 98.387.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below.

- We replaced the procedures and calculations proposed in 40 CFR part 98, subpart LL with references to the 40 CFR part 98, subpart MM procedures and calculations. As a result of considerable comment and EPA analysis, 40 CFR part 98, subpart MM procedures and calculations were significantly updated. Since the procedures and calculations necessary for sampling, testing, and measuring coal-to-liquid products are intrinsically linked to the procedures and calculations used for petroleum products, we concluded that referencing 40 CFR part 98, subpart MM in 40 CFR part 98, subpart LL would achieve consistency and completeness.
- We reorganized and updated 40 CFR 98.386 by mirroring 40 CFR 98.396 in order to reflect the updates we made to procedures and calculations and to assist in EPA data verification.

3. Summary of Comments and Responses

EPA did not receive any specific comments on proposed 40 CFR part 98, subpart LL (suppliers of coal-based liquid fuels). Changes made to this subpart were implemented to ensure consistency with changes made to 40 CFR part 98, subpart MM based on public comments provided and EPA analysis conducted.

MM. Suppliers of Petroleum Products

1. Summary of the Final Rule

Source Category Definition. Suppliers of petroleum products consist of:

• *Petroleum refineries* that produce petroleum products through distillation of crude oil.

• *Importers* who satisfy the same meaning given in 40 CFR 98.6, including any entity that imports petroleum products or NGLs as listed in Table MM–1 of 40 CFR part 98, subpart MM. Any blender or refiner of refined or semi-refined petroleum products shall be considered an importer if it otherwise satisfies the aforementioned definition.

• *Exporters* who satisfy the same meaning given in 40 CFR 98.6, including any entity that exports petroleum products or NGLs as listed in Table MM–1 of 40 CFR part 98, subpart MM. Any blender or refiner of refined or semi-refined petroleum products shall be considered an exporter if it otherwise satisfies the aforementioned definition.

Suppliers of petroleum products that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble must report GHG emissions that would result from the complete combustion or oxidation of the product(s) they supply.

GHGs to Report. Suppliers of petroleum products must report annually:

• CO_2 emissions that would result from the complete combustion or oxidation of each petroleum product and natural gas liquid produced, used as feedstock, imported, or exported during the calendar year.

• CO_2 emissions that would result from the complete combustion or oxidation of any biomass co-processed with petroleum feedstocks at a refinery.

Suppliers of petroleum products are not required to report data on emissions of other GHGs that would result from the complete combustion or oxidation of their products, such as CH_4 or N_20.

GHG Emissions Calculation and Monitoring. Suppliers of petroleum products must choose one of two methods to calculate CO_2 emissions that would result from the combustion or oxidation of each petroleum product and natural gas liquid:

• Method 1: Use the default CO_2 emission factors provided in the regulations for a given petroleum product or NGL; or

• Method 2: Develop an emission factor for a given petroleum product or natural gas liquid using direct measurements of density and carbon share.

To calculate CO_2 emissions that would result from the combustion or oxidation of biomass co-processed with petroleum feedstock, reporters must use a CO_2 emission factor that is provided in the regulations for each type of biomass.

In calculating total CO_2 emissions that would result from the combustion or oxidation of all petroleum products and natural gas liquids that leave the refinery, refineries must subtract the emissions from petroleum products and natural gas liquids that enter the refinery to be further refined or used on site as well as biomass and biomass-based fuels that are co-processed or blended with petroleum feedstocks.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data used to calculate GHG emissions that would result from the complete combustion or oxidation of the product(s) supplied as well as information on the characteristics of crude oil used at a refinery. The specific list of data to be reported for this source category is contained in 40 CFR part 98.396 and includes information to support the data verification process.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to determine the quantities and characteristics of product(s) reported under this subpart and to calculate GHG emissions that would result from the complete combustion or oxidation of the product(s) supplied. A list of specific records that must be retained for this source category is included in 40 CFR part 98.387.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart MM: Suppliers of Petroleum Products.''

• We established a reporting threshold for importers and exporters of 25,000 metric tons of CO_2 per year.

• We changed the source category definition of petroleum refinery for the purposes of 40 CFR part 98, subpart MM to only include facilities that process crude oil. As such, we are not requiring reporting from facilities that only handle intermediary petroleum products.

• We refined the definition of importers and exporters of petroleum products to clarify reporting requirements for blenders.

• We are not requiring reporters to rely on an exclusive list of standard methods for the measurement of the quantity of products or the calibration and recalibration of equipment. Instead, reporters must use an appropriate standard method published by a consensus-based standards organization. If no such standard exists, reporters are allowed to rely on industry standard practices.

• We provide more flexibility in the frequency of equipment recalibration. Reporters must now comply with the frequency specified by the manufacturer's directions or the selected quantity measurement method.

• We removed the option for reporters to directly measure density but not carbon share under Calculation Method 2. We determined that using a measured density and a default carbon share factor will likely adversely affect the accuracy of the calculated emission factor since the density and carbon share of hydrocarbons are, in the absence of impurities, correlated.

• We are not requiring reporters to rely on an exclusive list of standard methods for sampling products, measuring density, and measuring carbon share under Calculation Method 2. Instead, reporters must use an appropriate standard method published by a consensus-based standards organization.

• We added more specific requirements for the frequency of sampling under Calculation Method 2 and now allow for mathematical composites of samples in addition to physical composites of samples.

• To ensure consistent accounting of denaturant across reporters, we are requiring reporters to assume that 2.5 percent of the volume of any ethanol product that is blended into a petroleum-based product is a petroleum-based denaturant. See below for further explanation.

• For bulk NGLs, reporters must calculate the emissions that would result from the complete combustion or oxidation of the individual components that constitute the NGL (i.e., ethane, propane, butane, isobutane, and pentanes plus).

• We updated the definition of petroleum products to be clear that no petroleum product supplier must report on plastics and plastic products and that importers and exporters must report on asphalt, road oil, and lubricants.

- We updated the default emissions factors based on technical research since the proposal. We updated certain factors to correct technical errors and to reflect more recent data. We expanded the factors to four significant digits to enhance precision. We also added grade-based sub-categories of finished motor gasoline and blendstocks, combined diesel and fuel oil categories into ''distillate fuel'' categories, and added sulfur-based subcategories of distillate fuel No. 1 and 2 to better distinguish between product categories with potentially different carbon contents. Full documentation of default emissions factors can be found in the TSD.
- We updated 40 CFR 98.396. First, we made 40 CFR 98.396 more specific, in some cases breaking up one reporting requirement into two for clarity. Second, to allow for EPA verification of reporter calculations, we added reporting requirements for data that a reporter must already use to calculate GHGs as specified in 40 CFR 98.393 through 98.396. Third, after removing the prescriptive list of allowable methods, we added data reporting requirements on the method selected to measure quantity, density, and carbon content and the method selected to sample in order to track the appropriateness of these methods.

We require reporters to assume that ethanol contains 2.5 percent petroleum-based denaturant because we want to ensure that reporters account for the CO_2 emissions that would result from the combustion or oxidation of the denaturant. All ethanol that is blended with petroleum products reported in 40 CFR part 98, subpart MM should contain more than 1.96 percent petroleum-based denaturant by volume, per the requirements in 27 CFR Parts 20 and 21 to make ethanol non-potable. We considered relying on reporters to estimate the percent volume of denaturant in their products, but we determined that, in many cases, reporters would not know this information. We have concluded that 2.5 percent is a suitable assumption for the level of denaturant since, according to an Internal Revenue Service interpretation of Section 15332 in the Food, Conservation, and Energy Act of 2008 in notice 2009–06, ethanol containing greater than 2.5 percent denaturant by volume would not be eligible for the full value of the Volumetric Ethanol Excise Tax Credit. There may be cases where ethanol containing less than 2.5 percent denaturant is blended with petroleum-based products, but we concluded that it is better to conservatively account for potential petroleum-based carbon emissions rather than arbitrarily pick a number between 1.96 percent and 2.5 percent.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on suppliers of petroleum products were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart MM: Suppliers of Petroleum Products.''

Selection of Threshold

Comment: In the proposed rule, EPA sought comment on whether or not to establish a *de minimis* level of imported and exported petroleum products, either in terms of the quantity of products or the CO_2 emissions associated with the combustion or oxidation of products, to eliminate any reporting burden for parties that may import or export a small amount of petroleum products on an annual basis. In response, EPA received several comments in support of establishing some type of *de minimis* value, including a threshold of 25,000 metric tons of CO_2 from the complete combustion or oxidation of all products from individual importers and exporters. EPA also received at least one comment in support of establishing a threshold value for refineries reporting under 40 CFR part 98, subpart MM.

Response: In today's rule, we are establishing a threshold of 25,000 metric tons of CO_2 per year for importers and exporters of petroleum products and natural gas liquids; the threshold is based on a calculation of CO_2 emissions that would result from complete combustion or oxidation of the imported or exported petroleum products and natural gas liquids.

When we conducted the threshold analysis for the proposed rule, we estimated from EIA data that 224 companies would be covered in 40 CFR part 98, MM as importers. Through this analysis, we found that at a threshold of 25,000 metric tons CO_2 per year, 175 importers and 99.9 percent of total emissions that would result from the combustion or oxidation of imported products would be covered by the proposed rule. Therefore, establishing a 25,000 metric ton CO_2 threshold would drop 49 reporters in exchange for a 0.1 percent drop in total emissions. Nonetheless, we decided to propose reporting for all importers because we felt the reporting burden would be minimal since importers already report the product quantity data to other Federal agencies.

Since proposing the rule, EPA has learned new information, through comments and research, about importers that could be covered as reporters under 40 CFR part 98, Subpart MM. EPA may have omitted some importers of small volumes of petroleum products or natural gas liquids from our original threshold analysis, due to lack of public data. We never intended to cover such small volume imports with this rule (e.g., importers of non-fossil fuel products that contain small quantities of petroleum or natural gas liquids, such as butane lighters). Therefore, for the final rule, EPA concludes that establishing a 25,000 metric ton CO_2 threshold for importers will relieve burden on importers of insignificant quantities of petroleum products and natural gas liquids that we never intended to cover with this rule without significantly diminishing the amount of information received by the agency. In addition, a 25,000 metric ton CO_2 threshold is consistent with other upstream fuel and industrial gas supplier thresholds for importers and exporters in today's rule.

When we conducted the threshold analysis for the proposed rule, we could not estimate the number of exporting companies that would be covered in 40 CFR part 98, subpart MM because the necessary data was not publically available. Nonetheless, we decided to propose reporting for all exporters because we concluded that the reporting burden would be minimal given the type of information that exporters must maintain as part of their normal business operations.

Since proposing the rule, based on analogous information learned on importers, EPA has concluded that some exporters of very small volumes of petroleum products or natural gas liquids could be covered as reporters under 40 CFR part 98, subpart MM. We never intended to cover such small volume exporters with this rule (e.g., exporters of non-fossil fuel products that contain small quantities of petroleum or natural gas liquids, such as butane lighters). Therefore, for the final rule, EPA has concluded that establishing a threshold for exporters will relieve burden on exporters of insignificant quantities of petroleum products and natural gas liquids that we never intended to cover with this rule. In today's rule, we have selected a 25,000 metric ton CO_2 threshold because we conclude that it will not significantly diminish the amount of information received by the agency;

overall, exports of refined and semi-refined products are lower than imports, so the threshold adopted for imports will be adequate for collecting data on exports. In addition, a 25,000 metric ton CO_2 threshold is consistent with other upstream fuel and industrial gas supplier thresholds for importers and exporters in today's rule.

In today's rulemaking, we require all refineries as defined in 40 CFR part 98, subpart MM to report, as was proposed. Our threshold analysis of refineries in the proposed rule indicated that all refineries would be covered even if we were to establish a 100,000 metric ton CO_2 threshold. Furthermore, we have determined that all refineries covered by this subpart are already tracking the necessary data to comply with the reporting requirements so the requirements would not pose an undue burden.

Monitoring and QA/QC Requirements

Comment: EPA received several comments that the proposed approach to determining product quantity was too prescriptive. These comments indicated that the list of allowable methods and equipment types for determining the quantity of products in the proposed rule was incomplete, would result in significant costs for industry, and could adversely impact the quality of the measurements. Commenters noted that industry uses a much larger and ever-growing number of industry methods and equipment types to determine quantity for purposes of product transfers and financial records, including methods and equipment types used to comply with Internal Revenue Service, Securities and Exchange Commission, and Department of Homeland Security's Bureau of U.S. Customs & Border Protection regulations. Commenters suggested that EPA's ability to develop and maintain a comprehensive list of methods would require considerable resources, since companies and consensus-based standards organizations review quantity measurement methods regularly to ensure consistency with technological changes and advancements. Commenters also suggested that methods may improve over time for certain products as a direct result of this rulemaking.

Response: In today's rule, we are addressing these concerns by adopting an approach that recognizes the multitude of appropriate industry standard methods and practices and leaves open the possibility that industry may adopt better methods, equipment, and practices over time to determine quantities of products. EPA is requiring that petroleum product suppliers use an appropriate standard method developed by a consensus-based standards organization, when such a standard method exists. If no such standard method exists, reporters are allowed to follow industry standard practices. Consensus-based standards organizations include organizations such as ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and North American Energy Standards Board (NAESB). Reporters must ensure that all equipment used for measuring quantity is calibrated and periodically recalibrated according to the manufacturer's directions or specifications in the appropriate consensus-based industry standard method.

In order to further EPA's understanding of the methods and equipment that reporters use, and to help us better assess the appropriateness of the standard methods and industry practices that individual reporters select, we are requiring that all petroleum product suppliers report the standard method or industry standard practice they use to measure each distinct product quantity that they report to EPA.

Comment: Several commenters recommended that EPA provide more flexible approaches to the direct measurement of carbon share and density under Calculation Method 2. Some noted that the proposed requirement to test samples at the end of the year could negatively impact the integrity and quality of those samples. These commenters suggested that EPA allow reporters to test samples monthly and create a mathematical composite of these test results at the end of the year. Some commenters suggested that EPA develop a mechanism whereby reporters could reduce the frequency of sampling once the reporter demonstrates that the variability in the density and carbon share of the product is sufficiently small, and even eliminate direct measurement requirements and allow reporters to use emissions factors developed in previous years. We also received comments requesting that we expand our list of acceptable carbon share measurement methods.

Response: We have incorporated several of the suggestions to increase the flexibility of the Calculation Method 2 approach in today's rule. Reporters are now allowed to test their monthly samples throughout the year and conduct a mathematical composite of the test results at the end of the year. We have also expanded the list of acceptable sampling, density, and carbon share methods to include any appropriate standard method published by a consensus-based standards organization.

We could not determine an adequate approach for allowing reporters to reduce the sampling frequency of products based on statistical evidence of low variability in the density and carbon share for a given product. We want to capture changes in product characteristics over time and have determined that taking monthly samples of an entire product category would not be overly burdensome. Furthermore, reporters are allowed to use default factors under Calculation Method 1 if they so choose.

Data Reporting Requirements

Comment: EPA received several comments requesting that we eliminate reporting requirements related to products that have potentially non-emissive uses, including plastics and plastic products, petrochemical feedstocks, petroleum coke sent to landfill, asphalt and road oil, and lubricants and waxes. One commenter questioned the incongruity in reporting requirements proposed for refiners, who would report on all products, and importers and exporters who would not be required to report on asphalt, road oil, lubricants, waxes, plastics, and plastic products.

Response: Today's rule requires reporting on products with potentially non-emissive uses. Comprehensive upstream data will provide EPA with a full accounting of the emissions that would result from the complete combustion or oxidation of all petroleum products and natural gas liquids introduced into the economy. Furthermore, comprehensive facility-level data can help us conduct a more robust mass balance assessment for data verification purposes. While we recognize that carbon in some petroleum products, such as asphalt, can remain un-oxidized for long periods, petroleum product supplier cannot always know with certainty whether or not the carbon in their products will be released into the atmosphere. Even asphalt can be burned as fuel or incinerated as waste. In the *Inventory of US Greenhouse Gas Emissions and Sinks,* EPA notes several areas of uncertainty surrounding the fate of carbon in petroleum products including those for which the Inventory assumes a 100 percent storage factor for the purposes of the national inventory (e.g., asphalt roofing, asphalt cement, and asphalt paving materials). As discussed in the proposal, a comprehensive and rigorous system for tracking the fate of petroleum products that may have non-emissive uses is beyond the scope of this rule, and would require a much more burdensome reporting obligation for petroleum product suppliers and other downstream users of petroleum products and natural gas liquids. The data reported as a result of this rulemaking will allow EPA to conduct further research in the future on the pathways and ultimate fate of products with potential non-emissive uses.

It was never EPA's intention to require reporting on plastics and plastic products, so we made this explicit in the definition of petroleum products as well as our definition of a refinery in 40 CFR part 98, subpart MM, which now excludes any facility (e.g. a plastics manufacturing plant) that does not process crude oil. Any CO_2 emissions that would result from the combustion or oxidation of plastics and plastic products manufactured in the U.S. should already be accounted for when a petroleum product supplier introduces the petrochemical feedstock (e.g., propylene) into the economy.

In response to comments on the incongruity of the reporting burden for refiners compared to importers and exporters, we have reevaluated the list of petroleum products with potentially non-emissive uses that importers and exporters do not have to report. In the proposed rule, this list included asphalt, road oil, lubricants, waxes, plastics, and plastic products. Our rationale for excluding these products for importers and exporters was our assessment that there is a much larger variety of these products entering and leaving the country than is produced at a petroleum refinery. Upon further consideration, however, we have concluded that only waxes, plastics, and plastic products would pose an undue administrative burden on importers and exporters. Waxes, plastics, and plastic products enter and leave the country in wide-ranging forms (e.g., cosmetics, candles, lawn furniture, plastic wear) making it difficult to accurately assess the petroleum-based carbon content of these products. We have concluded that the types of asphalt, road oil, and lubricants imported in and exported from the country is much less variable, and importers already track these products and report the quantities to EIA. We have also established a 25,000 metric ton CO_2 annual reporting threshold for importers and exporters in today's rule, which should reduce the number of reporters and minimize the reporting of products that are imported or exported in very low quantities. Therefore, we are requiring importers and exporters to report the volume and CO_2 emissions that would result from the complete combustion or oxidation of the asphalt, road oil, and lubricants they supply.

In response to comments that collecting data on products with potentially non-emissive uses will overestimate actual emissions released into the atmosphere, EPA has and will continue to characterize CO_2 emissions data reported under 40 CFR part 98, subpart MM as emissions that would result from the complete combustion or oxidation of the reported product(s) and not as actual emissions.

Comment: EPA received many comments urging us to leverage data that petroleum product suppliers already report to the Energy Information Administration (EIA) and to follow EIA's data collection procedures and protocols. For example, one commenter urged EPA to require refiners on a facility-level and company-wide basis to report to EPA the same level of information on crude imports and processing that is currently reported to the EIA and to follow a process similar to the one used by the EIA; and another commenter urged us to align our reporting requirements with what the industry is already providing to the EIA. Some commenters, urged EPA to make use of data already reported to EIA or other Federal agencies instead of requiring reporting directly to EPA through this rulemaking. EPA also received comments recommending that EIA reporting remain separate from the reporting requirements of this rule.

Response: In the proposed rulemaking, EPA stated that we considered, but did not propose, the option of obtaining data by accessing existing Federal government reporting databases and we sought comment on this decision.

In today's rulemaking, we are requiring reporters to report data directly to EPA. We have determined that in order to collect facility-level data from refineries (and company-level data from importers and exporters) that is consistent with other reporters in this rule, in terms of timing, reporting, and verification procedures, we are not able to rely upon EIA data. In addition, EIA relies on a number of legal authorities to pledge confidentiality to statistical survey respondents for company-level information. Some data are collected with legal authority from the Confidential Information Protection and Statistical Efficiency Act of 2002 (CIPSEA), under which reported information must be held in confidence and must be used for statistical purposes only. Collection of data directly by EPA in a central system will allow EPA to electronically verify and publish the data quickly, to use the information for non-statistical purposes, and to handle confidential business information in accordance with the CAA (see the general provisions preamble for addition discussion on CBI). In today's rulemaking we did not replicate EIA's reporting requirements and methodologies if we did not consider them sufficient to achieve our objective, which is to collect comprehensive and accurate data on the CO_2 emissions that would result from the complete combustion or oxidation of petroleum products introduced into the economy. For example, we provide a comprehensive list in Tables MM–1 and MM–2 of 40 CFR part 98, subpart MM, according to which reporters must categorize their products for reporting under today's rulemaking. This list differs from EIA's list of products, according to which reporters must report to EIA. Some of the products are the same on both lists (e.g., aviation gasoline and kerosene) while some products are classified differently on one list than on the other (i.e., EPA's list breaks reformulated gasoline up by summer and winter varieties while EIA breaks reformulated gasoline up by type of oxygenate blended into it). We crafted EPA's product list carefully and we feel that each category has the potential to have a unique carbon share and/or density. Overall, the items on our list are common products in commerce and are already tracked by refineries, importers, and exporters. Therefore, we estimate that the additional burden to comply with this rule will be minimal.

NN. Suppliers of Natural Gas and Natural Gas Liquids

1. Summary of the Final Rule

Source Category Definition. Suppliers of natural gas and natural gas liquids are:

- NGL fractionators, which are installations that fractionate NGLs into their constituent liquid products: ethane, propane, normal butane, isobutane or pentanes plus for supply to downstream facilities.
- Local natural gas distribution companies (LDCs) that own or operate distribution pipelines that deliver natural gas to end users. Companies that operate interstate pipelines transmission or intrastate transmission pipelines are not part of this source category.

Suppliers of natural gas and NGLs that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble must report GHG emissions that would result from complete combustion or oxidation of products they supply.

GHGs to Report. Natural gas fractionators must report CO_2 emissions that would result from the complete combustion or oxidation of the annual quantities of propane, butane, ethane, isobutene, and pentanes plus supplied.

Local distribution companies must report CO_2 emissions that would result from the complete combustion or oxidation of the annual volume of natural gas distributed to their customers.

Suppliers of natural gas and NGLs are not required to report data on emissions of other GHGs that would result from the complete combustion or oxidation of their products, such as CH_4 or N_20.

GHG Emissions Calculation and Monitoring. Reporters must use one of two methods to calculate the CO_2 emissions that would result from the complete combustion or oxidation of natural gas supply or NGL supply:

- One method uses either a measured or default fuel heating value and either a measured or default CO_2 emissions factor. This method is most appropriate for liquid fuels.
- The second method uses either a measured or default CO_2 emissions factor. This method is most appropriate for gaseous fuels.
- A NGL fractionator must then follow two additional equations, if applicable, to subtract the CO_2 emissions that would result from the complete combustion or oxidation of NGL supply that are double-counted. A LDC must then follow up to four additional equations, if applicable, to subtract the CO_2 emissions that would result from the complete combustion or oxidation of natural gas supply that is double-counted.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate natural gas or NGL supply. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart NN.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate natural gas or NGL supply. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart NN.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart NN: Suppliers of Natural Gas and Natural Gas Liquids.''

- We changed the source category responsible for reporting NGL supply in 40 CFR part 98, subpart NN from all natural gas processors to only facilities that fractionate natural gas liquids.
- We eliminated the requirement to report bulk NGL since NGL fractionators do not supply bulk NGL.
- We added equations to calculate emissions that would result from the oxidation or combustion of the following volumes of natural gas and NGLs because they should be subtracted from the reporter's total emissions calculation, when applicable: fractionated NGLs received from other fractionators; natural gas injected for storage; natural gas delivered to individual customers already reporting under another Subpart of this rule; and natural gas delivered by an LDC to another LDC.
- We clarified the points of measurements for reporting purposes.
- We changed the rule to allow local distribution companies to use transmission pipeline metered volumes and calculated heating value where the local distribution companies do not perform their own measurements.
- We provide flexibility in frequency of equipment calibration, requiring reporters to comply with standard industry practices for measurements used for billing purposes as audited under Sarbanes Oxley regulations.
- We added a procedure for measuring the carbon content of blends of NGLs since NGL fractionators may supply blends of NGLs.
- We updated 40 CFR 98.406. First, we made 40 CFR 98.406 more specific, in some cases breaking up one reporting requirement into two for clarity. Second, to allow for EPA verification of reporter calculations, we added reporting requirements for data that a reporter must already use to calculate GHGs as specified in 40 CFR 98.403 to 40 CFR 98.406. This includes the addition of reporting requirements for new calculations introduced in the final rule to prevent supply double-counting. Third, after removing the prescriptive list of allowed standards and methods, we added data reporting requirements on the method selected to measure quantity, HHV, and carbon content. Fourth, we added a reporting requirement for the quantity of odorized propane. Fifth, we added data reporting requirements for inputs received by a NGL fractionator in order to conduct verification using a mass-balance approach.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on suppliers of natural gas and NGLs were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart NN: Suppliers of Natural Gas and Natural Gas Liquids.''

Definition of Source Category

Comment: EPA received many comments on the non-emissive use of natural gas liquids (NGLs). In general, these comments stated that NGLs such as ethane, butane, and isobutene, are either used as feedstocks in the petrochemical industry or as blendstocks that are reported by refineries in 40 CFR part 98, subpart MM, and should not be reported as though they are completely combusted or oxidized. Several commenters proposed that odorized propane should be the focus of 40 CFR part 98, subpart NN rather than all NGLs because odorized propane is the only NGL that is combusted as fuel.

Response: Today's rule still requires reporting on all NGL products, even those with potentially non-emissive uses. Comprehensive upstream data will provide EPA with a full accounting of the emissions that would result from the complete combustion or oxidation of all natural gas liquids introduced into the economy.

As discussed in the proposal, a comprehensive and rigorous system for tracking the fate of natural gas liquids that may have non-emissive uses is beyond the scope of this rule, and would require a much more burdensome reporting obligation for NGL fractionators and downstream users of natural gas liquids. Based on the data available today, we do not believe that a NGL fractionator can know with certainty whether or not the carbon in their products will be released into the atmosphere. The data reported as a result of this rulemaking will allow EPA to conduct further research on the pathways and ultimate fate of NGL and to refine our understanding of and policy on products with potential non-emissive uses.

Therefore, EPA does not concur with the proposal to replace NGL reporting with propane odorizers. However, EPA concurs that odorized propane lines up closely with propane combusted downstream, and that data collection on odorized propane would help EPA decide if and how to carry out a wide variety of CAA provisions on emission sources, as authorized broadly under CAA sections 114 and 208. As a result, we have added reporting requirements on the volume of propane odorized on site in today's rule.

We do not concur that products reported under 40 CFR part 98, subpart NN, such as isobutane to be blended with fuel, will be double-counted as products reported under 40 CFR part 98, subpart MM. Subpart MM requires refineries to report all non-crude feedstocks that enter the facility in order to subtract the emissions that would result from the oxidation or combustion of those products from their calculations. Such methodology allows EPA to collect data on the entire petroleum and natural gas liquids system without any double-counting.

Finally, in response to comments that collecting data on products with potentially non-emissive uses will overestimate actual emissions released into the atmosphere, EPA will continue to characterize CO_2 emissions data reported under 40 CFR part 98, subpart NN as emissions that would result from the complete combustion or oxidation of the reported product(s) and not as actual emissions.

Comment: Many commenters discouraged EPA from requiring reporting from natural gas processors. In general, these comments stated that processors do not know the constituents of the gas they process. They further stated that since bulk NGLs are often sent from one processor to another, reporting by processors on bulk NGLs would result in double-counting of supply. Ultimately, several commenters were confused by the multiple definitions provided in the rule for a natural gas processor and were not clear on the exact covered party in 40 CFR part 98, subpart NN.

Response: In the final rule, we specify the source category as NGL fractionators rather than as natural gas processors, and we have removed the requirement to report bulk NGLs. To avoid any remaining potential for double-counting, we provide an equation for a fractionator to subtract from its calculations any NGL constituents received from other fractionators that would report those products under this rule.

By requiring reporting from NGL fractionators, we have removed the need for the term ''natural gas processor'' in 40 CFR part 98, subpart NN. Multiple definitions for this term no long exist in the rule.

Monitoring and QA/QC Requirements

Comment: Many commenters interpreted EPA's measurement and calibration requirements differently than we intended, and as a result pressed upon EPA the inability of industry to reasonably meet such requirements. Many commenters interpreted that EPA required meter reading and calibration of every customer meter. Other commenters interpreted that EPA required daily measurement totals of throughput.

Response: In today's rule, we provide precise language to remove any confusion about monitoring and QA requirements. First, we clarify that the point of measurement for natural gas supply is the city gate meter. If the LDC makes its own measurements at the city gate according to business as usual practices, then it must use its own measurements. If not, it must use the delivering pipeline invoices measurements. The only exceptions are that the point of measurement for natural gas delivered to large end-users is the customer meter and the point of measurement for natural gas stored or removed from storage is the appropriate storage meter. However, we clarify that customer meters and storage meters are not subject to the 40 CFR part 98, subpart NN calibration requirements.

Second, we clarify that the minimum frequency of the measurements of quantities of NGLs and natural gas shall be based on the reporter's standard practices for commercial operations. For NGL fractionators the minimum frequency of measurements shall be the measurements taken at custody transfers summed to the annual reportable volume. For natural gas the minimum frequency of measurement shall be based on the LDC's standard measurement schedules used for billing purposes and summed to the annual reportable volume. If daily measurements are not standard practice for a reporter, then that reporter need not conduct daily measurements.

EPA clarifies in the final rule that customer meters do not face calibration requirements under 40 CFR part 98, subpart NN. Other equipment used to measure quantities must be calibrated prior to their first use for reporting under this subpart, using a suitable standard test method published by a consensus based standards organization or according to the equipment manufacturer's directions. Such equipment must also be recalibrated at the frequency specified by the standard test method used or by the manufacturer's directions. EPA has concluded that initial calibration requirements are necessary to ensure consistency across all reporters and accuracy of data. Since such a wide variety of calibration methods is allowed and since commenters stated that industry already calibrates carefully as a result of State Utility Commission and other regulations, EPA concluded that industry is already following such calibration requirements for usual business operations.

Data Reporting Requirements

Comment: EPA received many comments on the requirement for LDCs to report information on individual customers. In general, commenters interpreted the reason for EPA to collect this data differently than was intended. Many commented on the CBI nature of customer-specific delivery information. Others commented that LDCs do not or may not have access to the EIA or EPA numbers of their customers. One commenter told us that a LDC can only attest to the gas volume delivered through a single particular meter at a single particular location, which is not necessarily an individual customer.

Response: In the final rule, EPA has clarified that an LDC must report on customers that receive more than 460,000 million standard cubic feet (Mscf) per year in order to subtract that volume out of its total calculations. EPA's intention is to use this data to remove potential double-counting and to prevent a LDC from calculating and reporting an overstated supply volume. EPA can also use these data to verify that covered direct emitters are approximately reporting under the rule. In response to comments that LDCs do not or may not have access to customers' EIA or EPA numbers, we have changed the reporting of this from required to voluntary, if known. We have further specified that LDCs must report large volumes delivered to a single meter rather than to a particular end-user.

OO. Suppliers of Industrial GHGs

1. Summary of the Final Rule

Source Category Definition. Suppliers of industrial GHGs consist of the following:

• Facilities producing any fluorinated GHG or N_2O, except those that produce only HFC–23 generated as a byproduct during HCFC–22 production.

- Bulk importers of fluorinated GHGs or N_2O, if the total combined imports of industrial GHGs and CO_2 exceed 25,000 metric tons of CO_2e per year.
- Bulk exporters of fluorinated GHGs or N_2O, if the total combined exports of industrial GHGs and CO_2 exceed 25,000 metric tons CO_2e per year.

Suppliers of Industrial GHGs that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble must report industrial GHG supply flows.

GHGs to Report. Suppliers of industrial GHGs must report the amount of N_2O and each fluorinated GHG produced, imported, exported, transformed, or destroyed during the calendar year. Importers and exporters of CO_2 must calculate and report annual amounts of CO_2 according to 40 CFR part 98, subpart PP.

GHG Emissions Calculation and Monitoring. Suppliers must use the following methods to calculate annual industrial GHG supply flows:

- The mass of each fluorinated GHG or N_2O produced must be determined by measurements of gas production, less the mass of that GHG added to the process upstream (e.g., where used GHGs are added back to the production process for reclamation).
- The mass of each fluorinated GHG transformed must be determined considering the mass of fluorinated GHG fed into the transformation process and the efficiency of that process (as indicated by yield calculations or quantities of unreacted fluorinated GHGs or nitrous oxide permanently removed from the process and recovered, destroyed, or emitted).
- The mass of each fluorinated GHG destroyed must be determined by measurements of the mass of fluorinated GHG fed to the destruction device and a measurement of the destruction efficiency.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate industrial GHG supply flows or that can be used to verify industrial gas supply flows. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart OO.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart OO.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart OO: Suppliers of Industrial GHGs.''

- EPA has elaborated on the definition of ''produce'' to clarify what it does and does not include. The definition now explicitly includes (1) the manufacture of a fluorinated GHG for use in a process that will result in the transformation of that GHG (either at or outside of the production facility) and (2) the creation of a fluorinated GHG (with the exception of HFC–23) that is captured and shipped off site for any reason, including destruction. The definition now explicitly excludes the creation of by-products that are released or destroyed at the production facility.
- EPA has eased the accuracy and precision requirements for measuring production, transformation, and destruction. EPA is also permitting facilities flexibility in the frequency of measurements and calibration of measurement devices. Masses produced, fed into transformation processes, and fed into destruction devices must now be estimated to a precision and accuracy of one percent rather than 0.2 percent. Requirements to measure concentrations, which had previously been associated with the transformation and destruction provisions, have been changed to requirements to estimate concentrations or related quantities.
- EPA has eliminated the requirement that fluorinated GHG production facilities that destroy fluorinated GHGs annually verify the destruction efficiency of their destruction devices.
- EPA has added an additional method for estimating missing mass flow data in the event that a secondary mass measurement for that stream isn't available. In that event, producers can use a related parameter and the historical relationship between the related parameter and the missing parameter to estimate the flow.
- EPA has removed the option for reporters to develop their own methods for estimating missing data if they believe that the prescribed method will over- or under-estimate the data.
- EPA has added some reporting requirements to be consistent with the changes to the calculations and monitoring sections and to permit verification of emissions calculations.
- EPA has added an exemption from reporting requirements for import or export shipments containing less than 250 metric tons of CO_2e.
- EPA has clarified that the criteria for imported container heels at paragraph 98.417(e) set forth the conditions under which importers do not need to report heels; they do not establish requirements for all containers containing residual gas. If importers import containers with residual gas that does not meet these conditions, they must simply report these imports under paragraph 98.416(c). In addition, EPA is adding another condition under which imported heels do not need to be reported; that is the case in which the heels are recovered and included in a future shipment.
- EPA is requiring fluorinated GHG production facilities to submit a one-time report describing current measurement and estimation practices.

EPA is requiring the one-time report on measurement practices because the Agency is providing some flexibility to reporters regarding the methods that they use to calculate industrial gas supply flows. This flexibility permits reporters to use a larger range of methods and measurement equipment than were proposed, and it is important for EPA to understand the methods and equipment and their accuracies. Similar reports are required under EPA's Stratospheric Ozone Protection Regulations at 40 CFR part 82.

As noted above, EPA removed the option for reporters to develop their own methods for estimating missing data if they believe that the prescribed method will over- or underestimate the data. EPA removed this option for two reasons. First, the proposed provision lacked clear guidance on when alternative methods should be used (e.g., on the size of an underestimate that would justify use of an alternative method) and on how they should be developed. Second, the proposed provision was redundant with the new provision that permits reporters to estimate missing data using a related parameter and the historical relationship between the related parameter and the missing parameter. This new option provides reporters with flexibility in substituting for missing data in the event that a secondary mass measurement is not available, but sets out general guidance on how to select the substitute data.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on suppliers of industrial GHGs were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart OO: Suppliers of Industrial GHGs.''

Definition of Source Category

Comment: EPA received a number of comments regarding the proposed definition of ''fluorinated greenhouse gas.'' Several commenters argued that the proposed definition was too broad because it would include nonvolatile materials that could not be emitted to the atmosphere and materials for which GWPs had not been calculated. One commenter suggested establishing a lower vapor pressure limit for fluorinated GHGs (heat transfer fluids) of 400 Pa (0.004 bar, or three mm Hg absolute) at 25 C. Some commenters expressed the concern that the lack of GWPs for some covered compounds would lead to incomplete or inconsistent reporting because facilities would assign their own GWPs to compounds for which GWPs were not provided in Table A–1 of 40 CFR part 98, subpart A.

Some commenters recommended that EPA address these concerns by requiring reporting of only those fluorinated compounds listed in Table A–1 of 40 CFR part 98, subpart A. However, one of these commenters noted that the list in A–1 is incomplete and inconsistent, excluding for example, some high-GWP compounds whose low-GWP alternatives are included. This commenter recommended that EPA establish a ''visible and participative process'' to add other compounds as appropriate to Table A–1 of 40 CFR part 98, subpart A.

Response: In today's final rule, EPA is modifying the proposed definition of fluorinated GHG by adding an exemption for ''substances with a vapor pressure of less than one mm of Hg absolute at 25 degrees C.'' This modification ensures that non-volatile fluorocarbons such as fluoropolymers are excluded from reporting requirements, while requiring reporting of fluorocarbons (as well as SF_6 and NF_3) that could reasonably be expected to be emitted to the atmosphere.

As noted by several commenters, this definition would require reporting of some fluorocarbons to which GWPs have not been assigned in either IPCC or World Meteorological Organization (WMO) Scientific Assessments (i.e., fluorocarbons for which Table A–1 of 40 CFR part 98, subpart A does not provide GWPs). However, the lack of GWPs for some fluorocarbons will not impede reporting because EPA is requiring reporting of production and other quantities in tons of chemical rather than in tons of CO_2e. For purposes of determining whether or not the 25,000 metric ton CO_2e import or export threshold is exceeded, EPA is requiring facilities to include only substances whose GWPs appear in Table A–1 of 40 CFR part 98, subpart A.

EPA believes that this approach is prudent and appropriate. As acknowledged by commenters, Table A–1 of 40 CFR part 98, subpart A is not a complete listing of current or potential fluorinated GHGs; the IPCC and WMO lists on which it is based reflect only the facts that the listed materials have been synthesized, their atmospheric properties investigated, the results published, and the publications found by the IPCC and WMO Assessment authors. Table A–1 is known to omit some existing fluorinated GHGs and it unavoidably omits future fluorinated GHGs that have not yet been synthesized. Given the radiative properties of the carbon-fluorine bond, any fluorocarbon emitted into the atmosphere may have a significant GWP. This is true even for some fluorocarbons with lifetimes of less than one year, including, for example, HFE–356pcc3, with a lifetime of four months and a 100-year GWP of 110.

Reporting of fluorocarbons that do not appear in Table A–1 of 40 CFR part 98, subpart A will provide valuable information on the full range of volatile fluorocarbons entering U.S. commerce. This information can be used to assess the overall volume and importance of compounds for which GWPs have not been evaluated and to help identify which compounds should have their GWPs evaluated first. In addition, once GWPs have been identified for these compounds, historical reports in tons of chemical can be converted into CO_2e. Without a comprehensive reporting requirement, such historical information could be lost. Ultimately, all of this information can be used to inform policy decisions regarding the appropriate type and scope of emission reduction measures for these gases. Considering the modest cost of reporting production, import, and export of such compounds, the potential value of this information justifies a comprehensive definition of fluorinated GHG.

EPA agrees with commenters who noted that Table A–1 of 40 CFR part 98, subpart A should be periodically updated through a visible and participative process. EPA anticipates that as GWPs are evaluated or re-evaluated by the scientific community, the Agency will update Table A–1 of 40 CFR part 98, subpart A through notice and comment rulemaking. EPA may also, through rulemaking, establish a more proactive process for ensuring that GWPs are appropriately evaluated or re-evaluated.

Comment: EPA received comments both supporting and opposing a requirement to report imports of fluorinated GHGs contained in equipment and foams. Commenters supporting such a requirement noted that these imports comprised a significant fraction of U.S. consumption of fluorinated GHGs, that excluding these imports from reporting would put domestic manufacturers at a disadvantage and lead to leakage of manufacturing and increased emissions of GHGs, and that the burden of reporting these imports would be low, since there are relatively few importers and the reported information is easily accessible. Commenters opposing such a requirement stated that the benefit of reporting would be small because pre-charged equipment and foams are ''hermetically sealed systems that essentially emit no GHGs,'' while the cost would be high due to the large number of importers.

Response: EPA did not propose to require reporting of fluorinated GHGs contained in imported products because EPA was concerned that the administrative burden of such a requirement could be considerable, while the quantities imported in at least some types of products could be small. However, in the proposal EPA acknowledged that the quantities of fluorinated GHGs imported in pre-charged equipment and foams appeared significant, and that ascertaining the identity and quantity of fluorinated GHGs in these products might be relatively straightforward. EPA is continuing to research these issues, and is deferring the final decision on whether to include imports of equipment and foams containing fluorinated GHGs to a later rulemaking.

Monitoring and QA/QC Requirements

Comment: Several commenters stated that facilities could not meet the proposed accuracy, precision, and frequency requirements for their measurements of production, transformation, and destruction using existing equipment and practices. These commenters stated that they would need to expend significant funds (millions of dollars in some cases) and time to install Coriolis flowmeters in multiple streams and to implement daily sampling protocols to analyze the contents of these streams. One commenter requested that EPA revise its precision and accuracy requirements to one percent for measurements of mass. Other commenters argued that instead of establishing strict accuracy, precision, and frequency requirements for measuring production, EPA should permit facilities to use existing measurement instruments and practices, such as NIST Handbook 44 and the trial HFC reporting program patterned on EPA's reporting requirements for ozone-depleting substances.

Response: Given the limited amount of time before 2010 data collection must begin, EPA agrees that it is appropriate to ease the accuracy and precision requirements proposed for measuring production, transformation, and destruction. EPA is therefore revising these requirements in the final rule. EPA is also permitting facilities flexibility in the frequency of measurements and calibration of measurement devices.

This approach will permit facilities to begin measuring their production, transformation, and destruction for purposes of the rule beginning in January 2010, using their current practices and equipment. However, EPA is planning to revisit the precision and accuracy requirements for industrial gas supply as we review public comments and perform analyses related to proposed 40 CFR part 98, subpart L (fluorinated gas production), which is not included in today's final rule. This is because the accuracy and precision with which production facilities track production, transformation, and destruction can have a profound influence on the accuracy and precision of these facilities' fluorinated GHG emission estimates. For one method of monitoring F–GHG emissions under consideration, a one percent relative error in production mass measurements could result in a much higher relative error in the emissions estimate, e.g., over 90 percent at an emission rate of 1.5 percent. For other methods of monitoring F–GHG emissions, however, a one percent relative error in production mass measurements would not lead to large errors in emission estimates. For both 40 CFR part 98, subpart OO and 40 CFR part 98, subpart L, EPA's goal is to optimize methods of data collection to ensure data accuracy while considering industry burden.

PP. Suppliers of Carbon Dioxide (CO_2)

1. Summary of the Final Rule

Source Category Definition. Under the rule, suppliers of CO_2 consist of the following:

- Facilities with production process units that capture and supply 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.
- Facilities with CO_2 production wells that extract a CO_2 stream for the purpose of supplying CO_2 for commercial applications.
- Importers of bulk CO_2, if total combined imports of CO_2 and other GHGs exceed 25,000 metric tons of CO_2 equivalent (CO_2e) per year.
- Exporters of bulk CO_2, if total combined exports of CO_2 and other GHGs exceed 25,000 metric tons CO_2e per year.

This source category is focused on upstream supply. It does not cover: Storage of CO_2 above ground or in geologic formations; use of CO_2 in enhanced oil and gas recovery; transportation or distribution of CO_2; or purification, compression, on-site use of CO_2 captured on site, or processing of CO_2. This source category does not include CO_2 imported or exported in equipment, such as fire extinguishers.

Suppliers of CO_2 that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble must submit GHG reports.

GHGs to Report. Suppliers of CO_2 must report the mass of CO_2 in a stream captured from production process units and extracted from production wells, and the mass of CO_2 in containers that is imported and exported.

GHG Emissions Calculation and Monitoring. While this source category is focused on upstream supply of CO_2, EPA recognizes that all CO_2 supplied to the economy does not necessarily result in an emission. There are a variety of downstream applications for CO_2—some applications are emissive and some are non-emissive. Under this rulemaking, a CO_2 supplier facility must calculate the mass of CO_2 supplied quarterly by measuring the mass or volumetric flow of gas and multiplying by the CO_2 concentration, and density in the case a volumetric flow meter is used, of the gas or liquid, as specified below. EPA requires quarterly monitoring because EPA has concluded that the CO_2 concentration of the stream varies throughout the year, and a quarterly concentration number multiplied by a quarterly volume will generate more accurate calculation of CO_2 supply than annual measurements. EPA requires these quarterly numbers to be reported so that EPA can electronically verify the calculations. The CO_2 supplier must also provide information on the downstream CO_2 application, if known. Reporters must use the following methodologies, as applicable, for calculating CO_2 supplied:

- For suppliers that make measurements with mass flow meters, calculate quarterly for each meter the total mass of CO_2 in a CO_2 stream in metric tons, prior to any subsequent purification, processing, or compressing, according to Equation PP–1 of 40 CFR 98.423. Measure mass flow and concentration in accordance with 40 CFR 98.424.
- For suppliers that make measurements with volumetric flow meters, calculate quarterly for each meter the total mass of CO_2 in a CO_2 stream in metric tons, prior to any subsequent purification, processing, or compressing, according to Equation PP–2 of 40 CFR 98.423. Measure volumetric flow, concentration and density in accordance with 40 CFR 98.424.
- For suppliers that have multiple flow meters, aggregate data according to methods specified in Equation PP–3 in 40 CFR 98.423.
- Importers or exporters that import or export CO_2 in containers must calculate the total mass of CO_2 supplied in metric tons, prior to any subsequent purification, processing, or compressing, according to equation PP–4 of 40 CFR 98.423. Use weigh bills, scales, or load cells to measure the mass of CO_2 imported or exported in containers.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate CO_2 supply. A list of the specific data to be reported for this source category is contained in 40 CFR 98.426.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate CO_2 supply. A list of specific records that must be retained for this source category is included in 40 CFR 98.427.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in "Mandatory Greenhouse Gas

Reporting Rule: EPA's Response to Public Comments, Subpart PP: Suppliers of Carbon Dioxide.''

- We added equations and QA requirements to allow reporters to determine CO_2 quantity using volumetric flow meters, weigh bills, scales, or load cells, as appropriate. These additions supplement the proposed equations and quality assurance requirements to determine CO_2 quantity using mass flow meters.
- We revised the reporting procedures for missing data in 40 CFR 98.425. Facilities must use quarterly values as substitute data as they can no longer use annual average values. We added missing data procedures to allow for more quarterly data points to be used, as appropriate. EPA concluded that quarterly missing data values will generate more accurate estimates than annual average values.
- To improve the emissions verification process, we reorganized and updated 40 CFR 98.426. We moved some data elements from 40 CFR 98.427 to 40 CFR 98.426, and added some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.423 to 40 CFR 98.426 for clarity.
- We revised the reporting and calculation procedures to require facilities using flow meters to determine annual mass for every flow meter used. To aggregate data at the facility level for CO_2 being captured in production wells or production process units, we have added Equation PP–3.
- To decrease unnecessary sampling burden, we have removed the requirement of quarterly concentration sampling for importers and exporters that use containers of CO_2.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on suppliers of CO_2 were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart PP: Suppliers of Carbon Dioxide.''

Definition of Source Category

Comment: EPA received many comments about how we defined the source category in this Subpart. One group of comments stated that the CO_2 supplied to the economy should not be characterized as an emission. Some in this group of comments specified that much of the supplied CO_2 is stored at enhanced oil recovery (EOR) sites, which are ''closed systems'', rather than emitted. In general, these same commenters stated that any CO_2 reporting requirements placed by EPA on industry should be placed on downstream CO_2 users, such as EOR facilities, rather than CO_2 suppliers and should be for actual emissions only. Other comments echoed that EPA needs to collect data from recipients of supplied CO_2 such as EOR sites. This group pressed upon EPA the need to collect not only data on actual emissions but also data on injection, production, and geologic sequestration of CO_2. Some of the benefits cited for collecting such comprehensive data include: Assisting in ensuring no more than negligible releases at a facility if it is properly sited, designed, and permitted; achieving full public accountability of CO_2 geologic sequestration effectiveness; and tracking the CO_2 throughout the entire carbon dioxide capture and sequestration (CCS) chain for the purposes of adjusting CO_2 emissions reported or assigning offsets. Along those lines, some commenters urged EPA to rely on or expand the existing underground injection control (UIC) program to deal with CCS.

Response: EPA did not intend to characterize all CO_2 supplied to the economy as emissions and recognizes that there are a variety of applications for CO_2, both emissive and non-emissive. CO_2 supplied to the economy would result in an emission if the CO_2 were used in an application which would ultimately result in release of the CO_2 to the atmosphere. EPA is also collecting information from upstream suppliers in other subparts of this rulemaking such as natural gas supply and petroleum product supply.

EPA recognizes that, in order to determine whether or not supplied CO_2 has been or will be released to the atmosphere (e.g., emitted), the Agency needs information on the downstream CO_2 end-use. In today's final rulemaking, CO_2 suppliers must provide information on the downstream CO_2 application, if known. EPA believes information on the end-use will provide some idea of the amounts of CO_2 which are emitted. Where that end-use is geologic sequestration (at EOR or other types of facilities), EPA will need additional information on the amount of CO_2 that is permanently and securely sequestered and on the monitoring and verification methodologies applied. With respect to EOR, the geology of an oil and gas reservoir can create a good barrier to trap CO_2 underground. Because these formations effectively stored oil or gas for hundreds of thousands to millions of years, it is believed that they can be used to store injected CO_2 for long periods of time. However, EPA also recognizes that the requirements to identify a suitable GS site extend beyond geophysical trapping parameters alone and include: The evaluation and appropriate management of potential leakage pathways, appropriate rate and pressure of injection, appropriate monitoring, and other such features. While some amount of CO_2 injected into oil and gas reservoirs for EOR purposes will be trapped in the subsurface, these and other site-specific elements influence the amount of CO_2 securely sequestered and the potential for release of CO_2 during EOR operations.

Given the comments in support of downstream data collection, particularly with respect to EOR systems and CO_2 geologic sequestration (at EOR or other types of facilities), EPA plans to issue a new proposal on geologic sequestration and will consider how to address emissions and sequestration at active EOR facilities. EPA will take action on this issue in the near future with the goal that data collection for these types of facilities can begin as quickly as possible. EPA will seek comment on monitoring, reporting, and verification methodologies which can be used to determine the amount of CO_2 emitted and geologically sequestered at active EOR facilities and geologic sequestration sites where CO_2 is injected (for long-term storage) into saline aquifers, oil and gas reservoirs, or other geologic formations. Furthermore, as stated in Section III.W of this preamble, EPA plans to take additional time to consider alternatives to data collection procedures and methodologies in the proposed 40 CFR part 98, subpart W and will consider inclusion of GHG reporting from other sectors of the oil and gas industry besides those proposed for reporting in proposed 40 CFR part 98, subpart W. EOR surface facility operations may be part of those considerations. The data reported under subsequent regulatory actions and the data reported under today's rulemaking will together enable EPA to understand the amount of CO_2 supplied, emitted, and sequestered in the U.S., to carry out a wide variety of CAA provisions. The options that we will have considered and the resulting recommended approaches will be further fleshed out through a notice and comment process. See the next comment response for a discussion of why EPA still needs to collect CO_2 supplier data in today's rulemaking even though a new rulemaking on sequestration is planned.

In response to comments that EPA should rely on or expand the UIC program to address emissions of CO_2, that issue is outside the scope of this rulemaking. However, EPA agrees that the UIC program and EPA's authority under the Safe Drinking Water Act (SDWA) will provide a foundation for ensuring safe and effective containment of CO_2. However, SDWA is focused on permitting sites for protection of ground and drinking water; the new proposal discussed above will be designed to address issues related to the CAA. EPA intends to harmonize CCS requirements across relevant statutory or other programs in order to minimize any redundancy and any burden on reporters. The reporting requirements in today's rulemaking for CO_2 suppliers and the reporting requirements in new rulemaking for CO_2 geologic sequestration sites will complement each other and together they can be harmonized with reporting requirements under the UIC proposed rulemaking. In a new CAA rulemaking on geologic sequestration reporting, EPA will rely on UIC permit requirements to the maximum extent possible. EPA will seek comment on these issues and will also endeavor to issue a geologic sequestration GHG reporting rule in the same time frame as it has planned for the stand-alone UIC GS rulemaking.

Comment: EPA received comments requesting information on how CO_2 supply will assist EPA in developing future climate policy. Commenters stated that they do not believe CO_2 supply data will provide EPA with useful information. Commenters stated that data collection from CO_2 suppliers does not fit within EPA's mandate from Congress to measure upstream emissions only as appropriate.

Response: As discussed in Sections I.C and II.Q of this preamble, EPA is collecting data from CO_2 suppliers in today's rule to carry out a wide variety of CAA provisions, as authorized broadly under CAA Sections 114 and 208. For example, this data will enable EPA to evaluate the appropriate action to take under section 103 regarding non-regulatory strategies for pollution prevention. It will also inform evaluation of possible CAA regulation of the supplier and/or recipient of the CO_2 Data on CO_2 supply to the economy will allow EPA to make a well informed decision about whether and how to use the CAA to regulate facilities that capture, sequester, or otherwise receive CO_2 as an end-user.

Though CO_2 capture and geologic sequestration are occurring now on a relatively small scale, CCS is expected to play a major role in mitigating GHG emissions from a wide variety of stationary sources. According to the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2007 (EPA, April 2009), stationary sources contributed 67 percent of the total CO_2 emissions from fossil fuel combustion in 2007. The stationary sources represent a wide variety of sectors amenable to CO_2 capture; electric power plants (existing and new), natural gas processing facilities, petroleum refineries, iron & steel foundries, ethylene plants, hydrogen production facilities, ammonia refineries, ethanol production facilities, ethylene oxide plants, and cement kilns. Furthermore, 95 percent of the 500 largest stationary sources are within 50 miles of a candidate CO_2 reservoir.[22]

With this rule, EPA will begin building capacity to track the growth in CO_2 supply and learn about its disposition throughout the economy. EPA has concluded that we need data now from CO_2 suppliers—both industrial facilities and CO_2 production wells—in order to effectively track how the supply sources will change over time. For example, we will need to track if and by how much CO_2 captured from industrial facilities will offset or displace CO_2 produced from natural formations. Even after EPA begins collecting data on CO_2 geologic sequestration under the proposed new rulemaking (discussed above), EPA will continue to need data from CO_2 suppliers in order to track any CO_2 that is not sequestered.

Comment: EPA received some comments asking whether a specific situation results in coverage under 40 CFR part 98, subpart PP, and some comments requesting that their specific situation be exempt from coverage. For example, one commenter asked whether a facility separating CO_2 that is not supplied to downstream customers is a covered facility. Another asked that a pulp and paper mill that transfers a CO_2 stream to an adjacent facility by pipeline be exempt from 40 CFR part 98, subpart PP. Several commenters requested clarification on specific scenarios such as taking ownership of an already separated CO_2 stream for further processing, separating CO_2 for their own use, and operating versus owning the separation unit.

Response: EPA did not intend for 40 CFR part 98, subpart PP to cover facilities that take ownership of a CO_2 stream that has already been separated and removed from a manufacturing process or that has already been extracted from CO_2 production wells in order to do any of the following: Store it in above ground storage of CO_2; transport or distribute it via pipelines, vessels, motor carriers, or other means; purify, compress, or process it; or sell it to other commercial applications. 40 CFR part 98, subpart PP covers facilities that own or operate the equipment that physically separates and removes CO_2 from an industrial or manufacturing process or physically extracts CO_2 from production wells because we concluded that the entity with first touch of the CO_2 supply was the most logical point of coverage. We wanted to minimize any unnecessary duplicative reporting of the same CO_2 by being as specific as possible about who in the supply chain is responsible for reporting it.

We did not intend for this source category to include facilities that capture CO_2 for further processing or use within the fence line of the facility (e.g., for their own use). EPA proposed that 40 CFR part 98, subpart PP only cover CO_2 that is captured or extracted for purposes of sequestration or supply to other facilities for commercial applications because we concluded that CO_2 captured and used on-site is equivalent to an intermediary step in production rather than an actual supply of CO_2.

Comment: EPA received a comment requesting that ethanol plants and other facilities capturing CO_2 from biomass be exempt from Subpart PP.

Response: A long standing inventory convention adopted by the IPCC, the UNFCCC, the US GHG Inventory, and many other reporting programs is separate treatment of emissions of CO_2 from the combustion of biomass and biomass-based fuels from emissions of CO_2 from the combustion of fossil-based products. In national inventories, emissions from the combustion of biomass-based fuels are accounted for as part of a comprehensive system-wide tracking of carbon dioxide emissions and sequestration in the land-use, land-use change and forestry sector and the agriculture sector, rather than at the point of fuel combustion. Consistent with this approach, in the proposed and final rule, downstream emitters must only consider non-biogenic emissions when conducting a threshold analysis; however, downstream emitters must report both biogenic and non-biogenic emissions once they trigger the reporting threshold because data on non-biogenic emissions is useful and informative.

For the final rule, EPA has decided not to apply the same approach to

[22] Dooley, JJ, CL Davidson, RT Dahowski, MA Wise, N Gupta, SH Kim, EL Malone, ''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. May 2006. PNWD–3602. College Park, MD.

suppliers of CO_2. We have concluded that data on capture of biogenic CO_2 would be useful and informative because biogenic CO_2 can potentially be stored in GS sites, or displace fossil CO_2 applications. We need a full picture of the CO_2 being supplied into the economy. Though CO_2 capture and sequestration is occurring now on a relatively small scale, it is expected to play a major role in mitigating GHG emissions. Therefore information on all potential sources of CO_2 for sequestration is necessary for a complete picture. Thus, a facility that captures CO_2 from biomass and otherwise meets the applicability test is covered under 40 CFR part 98, subpart PP and is required to report all CO_2 supplied along with the percentage of that supply that is biomass-based.

Monitoring and QA/QC Requirements

Comment: A large number of commenters requested that volumetric flow meters be allowed for purposes of calculating CO_2 supply in place of or in addition to mass flow meters. These comments indicated that mass flow meters are not in operation at many covered facilities, and the cost to comply with such an equipment requirement would be unnecessarily high. Some commenters suggested that reporters should be allowed to use sales contracts to determine quantity of CO_2 as long as the CBI is protected. Some commenters indicated that CO_2 liquefaction and purification facilities do not operate flow meters for the course of usual business. One of these also commented that importers and exporters of CO_2 do not operate flow meters for the course of usual business if they handle the product in containers and requested consideration of this incongruity.

Response: As a result of these comments, EPA added two equations to the methodology section of 40 CFR part 98, subpart PP in today's rule in order to ensure that all covered CO_2 can be reported, irrespective of technical or physical conditions. Therefore, a reporter that measures CO_2 in a stream using a volumetric flow meter may use this volumetric flow meter to determine quantity rather than having to purchase and install a mass flow meter. EPA has concluded that providing this additional methodology reduces the burden on reporters without compromising the quality of data received by the agency. In addition, a reporter that imports or exports CO_2 in containers may use weigh bills, scales, or load cells to determine quantity because applying a mass flow meter would be technically impossible. EPA has concluded that providing this additional methodology reduces the burden on reporters without compromising the quality of data received by the agency.

The final rule does not require reporting from facilities that liquefy or purify CO_2 that has already been separated or removed from a manufacturing process or already extracted from production wells. Therefore we did not give consideration to the types of equipment in operation at such facilities.

Finally, the rule does not allow reporters to use sales contracts to determine quantity because EPA has concluded that reporters capturing or extracting CO_2 already operate mass or volumetric flow meters, or already determine quantities of CO_2 imported or exported in containers using weigh bills, scales, or load cells. EPA has concluded that mass and volumetric flow meters provide more accurate data than sales contracts.

IV. Mobile Sources

A. Summary of Requirements of the Final Rule

For manufacturers of engines used in mobile sources outside of the light-duty sector,[23] this rule includes new requirements for reporting emission rates of GHGs.[24] Mobile source engine manufacturers have been measuring CO_2 emission rates from their products for many years as a part of normal business practices and existing criteria pollutant emission certification programs, but they have not consistently reported these values to EPA. This final rule requires manufacturers to consistently measure and report CO_2 for all engines beginning with model year 2011 and other GHGs in subsequent model years.[25] Manufacturers meeting the definitions of ''small business'' or ''small volume manufacturer'' under EPA's existing mobile source emissions regulations will generally be exempt from any new GHG reporting requirements.[26]

In addition to CO_2, most manufacturers will now be required to report on two other major GHGs emitted by mobile sources, nitrous oxide (N_2O) and methane (CH_4). Although most current engines have relatively low emission rates of these GHGs compared to CO_2, these compounds have global warming potentials significantly higher than CO_2. It is important that EPA improve its understanding of these emissions from today's engines and monitor trends over time. The broad base of emission data that will begin to accrue from requirements in this rule will support emissions modeling by EPA and others, and will help guide future GHG policy.

Emissions of N_2O are related to catalytic treatment of engine exhaust, specifically aftertreatment of NO_X emissions. Therefore, we will require that manufacturers begin to measure and report N_2O emissions, but only for engine models that incorporate NO_X aftertreatment technology (as shown in Table IV–1 of this preamble). The program will not require N_2O reporting before model year 2013, and the requirements will only apply to new engines equipped with NO_X aftertreatment technology. (Manufacturers of some engine categories have employed aftertreatment for many years to meet NO_X standards; for other engine categories, manufacturers are unlikely to introduce NO_X aftertreatment technologies for some years to come.)

Emissions of CH_4 are a part of overall hydrocarbon emissions from mobile sources. Because CH_4 is not very reactive in the atmosphere, EPA has often excluded CH_4 from mobile source hydrocarbon regulations since it has not traditionally been a major determinant of ozone formation.[27] The new reporting requirements are necessary to evaluate the magnitude of mobile source CH_4 emissions from a GHG (rather than ozone precursor) perspective.

As described above, we are finalizing manufacturer reporting requirements for N_2O and CH_4 emission rates in order to understand current emissions of these GHGs and to monitor potential changes as technologies and policies change in the future. However, we believe that manufacturers may be able to provide

[23] Manufacturers of light-duty vehicles, light-duty trucks, and medium-duty passenger vehicles are not covered in this final rule.

[24] The term ''manufacturer,'' as well as the term ''manufacturing company,'' as used in this preamble, means companies that are subject to EPA emission certification requirements. This primarily includes companies that manufacture engines domestically and foreign manufacturers that import engines into the U.S. market. In some cases this also includes domestic companies that are required to meet EPA certification requirements when they import foreign-manufactured engines.

[25] For aircraft engine manufacturers, reporting requirements will apply for the engine models in production in 2011.

[26] Small business manufacturers will continue to be subject to measurement and/or reporting requirements for compliance with existing regulations.

[27] But *see Ford Motor Co.* v. *EPA,* 604 F. 2d 685 (D.C. Cir. 1979) (permissible for EPA to regulate CH_4 under CAA section 202 (b)). In addition, although CH_4 is not itself regulated, manufacturers subject to ''non-methane hydrocarbon'' standards have needed to determine CH_4 emission levels, in some cases by using a default value and in many cases by way of testing.

alternative test data (and/or other information including engineering judgments based on test data) that would give EPA a reasonable basis for estimating the likely N_2O and CH_4 emission rates for each certified engine family. Therefore, we are including a provision in this final rule that would allow a manufacturer the opportunity to provide such alternative information in lieu of N_2O and/or CH_4 test data for each engine family.

In assessing such alternative information, EPA would consider how well the information provided by the manufacturer allows EPA to reasonably anticipate the emission performance of each of the manufacturer's engines. For example, we expect that in most cases a manufacturer wishing to omit engine testing will provide EPA with N_2O test data from relevant testing programs (by such sources as industry collaboratives and/or from the suppliers of the catalytic NO_X aftertreatment systems they are using on an engine. We would expect the manufacturer to also include an explanation of the manufacturer's engineering judgment as to why the data should apply to the engine family in question. For CH_4 emissions, our primary concern is the potential for unusually high emissions from natural gas fueled engines. Thus, we expect that in most cases a manufacturer of such an engine will provide test data on similar engines with similar catalyst systems for hydrocarbon control (with an explanation of their engineering judgment as to why the data should apply to that engine family).

The reporting requirements related to C3 marine engines and turbofan and turbojet aircraft engines differ from other engine categories. As with other manufacturers, C3 marine engine and aircraft engine manufacturers will report CO_2 emission rates beginning in 2011 (for aircraft engines, they will report CO_2 separately for each mode of the landing and take-off (LTO) cycle used in the certification test, as well as the entire LTO cycle). For aircraft engine manufacturers, however, the reporting requirements will apply not just to engines introduced in that year, but for all engines still in production. (This should not require manufacturers to conduct any new testing, only to report existing data.) We are not requiring manufacturers of C3 marine engines and aircraft engines to measure or report N_2O or CH_4 emission rates because of unique aspects of their industries and technologies.

C3 marine engines are very large and manufacturers generally test them as they are installed into ships rather than in a laboratory setting. For this reason, we have determined that requiring the addition of new N_2O and CH_4 measurement equipment for C3 engines would not be practical, and, as proposed, are not requiring such reporting in this rule.

Since aircraft engine manufacturers are unlikely to employ NO_X after treatment devices in the foreseeable future, we did not propose requiring N_2O reporting from aircraft engines and are not finalizing any requirements in this final rule. We are not finalizing our proposed requirement that aircraft engine manufacturers measure and report CH_4, as we learned that aircraft jet turbine engines have been shown to consume CH_4 from the ambient air during the dominant operating modes.[28] However, unlike NO_X emissions from most mobile sources, NO_X emissions from aircraft have been shown to make a potential contribution to climate change.[29] For this reason, we are requiring that aircraft engine manufacturers report the NO_X emission data for the LTO modes and the overall LTO cycle for all engine models currently in production, and for new engines as they are introduced. Manufacturers are already measuring NO_X as part of current criteria pollutant certification requirements. NO_X emissions rate data from LTO modes will support modeling of overall NO_X emissions from aircraft.

For all engine categories, when a manufacturer certifies the engine in one year and then carries over the certification to subsequent years, EPA will not require re-testing of that engine model for reporting purposes.

As proposed, we are not including any requirements for mobile source fleet operators or State and local governments to report in-use travel activity or other emissions-related data in this final rule.

Table IV–1 of this preamble shows the basic reporting requirements we are finalizing in this notice for each engine category. We discuss in more detail how these reporting requirements will apply to manufacturers of each engine category in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Motor Vehicle and Engine Manufacturing.''

TABLE IV–1—FIRST MODEL YEAR FOR GHG REPORTING REQUIREMENTS

Engine category	CO_2	N_2O [a]	CH_4
Highway Heavy-Duty (engine and vehicle)	2011	2013 or NO_X AT	2012
Nonroad Diesel	2011	2013 or NO_X AT	2012
Marine Diesel (other than C3)	2011	2013 or NO_X AT	2012
C3 Marine	2011	None	None
Locomotives	2011	2013 or NO_X AT	2012
Small Spark-Ignition	2011	2013 or NO_X AT	2012
Large Spark-Ignition	2011	2013 or NO_X AT	2012
Marine Spark-Ignition	2011	2013 or NO_X AT	2012
Snowmobiles	2011	2013 or NO_X AT	2012
Highway Motorcycles	2011	2013 or NO_X AT	2012
Off Highway Motorcycles/ATVs	2011	2013 or NO_X AT	2012
Aircraft [b]	2011	None	None

[a] N_2O reporting for new engines begins in 2013 or when the manufacturer introduces NO_X aftertreatment technology, whichever is later.
[b] Applies to all turbofan and turbojet engines in production in 2011 with a rated output greater than 26.7 kilonewtons. Reporting of NO_X also required.

[28] Aerodyne, Rich Miake-Lye, AAFEX Methane presentation at the Seventh Meeting of Primary Contributors for the Aviation Emissions Characterization Roadmap, June 9–10, 2009.

[29] IPCC, *Aviation and the Global Atmosphere,* 1999, at *http://www.grida.no/climate/ipcc/aviation/index.htm,* and NOAA, Written Testimony of Dr. David W. Fahey, Hearing on ''Aviation and the Environment: Emissions,'' Before the Committee on Transportation and Infrastructure, Subcommittee on Aviation, U.S. House of Representatives, May 6, 2008.

B. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Motor Vehicle and Engine Manufacturers.''

- We are not finalizing the proposed requirements related to light-duty vehicles (including light-duty trucks and medium-duty passenger vehicles). EPA expects to propose a comprehensive light-duty GHG emission control program commencing in MY 2012 (*see Notice of Upcoming Joint Rulemaking to Establish Vehicle GHG Emissions and CAFE Standards, 74 FR 24007* (May 22, 2009)), which is likely to contain monitoring, reporting and GHG data retention requirements that would supersede any reporting requirements established in this rule. Eliminating light-duty reporting requirements from this final rule will avoid issues of inconsistency and duplication.
- We have revised our proposal that all engine manufacturers measure and report N_2O for all of their engines, and instead will require N_2O reporting only for engines that use NO_X exhaust aftertreatment technology.
- We have delayed the proposed MY 2011 start year for N_2O reporting until MY 2013, and later for categories where the manufacturer has not applied NO_X aftertreatment technology.
- We have added additional emission test methods that manufacturers can choose for measuring N_2O, to assure that an appropriate method is available for any foreseeable circumstance (including the need to measure very low N_2O emission rates).
- The final rule incorporates an opportunity for a manufacturer to provide EPA with appropriate alternative information in lieu of N_2O and/or CH_4 testing, as described above.
- We have added one year of lead time to the proposed start year for reporting of CH_4 emissions, until 2012.
- We are not finalizing our proposal to require reporting of CH_4 for aircraft engines because, for the dominant operating modes, jet engines may consume CH_4 in the air.
- We are finalizing a requirement that we took comment on in the proposal to have aircraft engine manufacturers report NO_X emissions data they already collect, since, at altitude, NO_X emissions from aircraft have been shown to make a potential contribution to climate change.
- Since aircraft engines are not certified every year (there is no annual certification as is the case with other mobile sources), we have removed references to ''model year'' in the regulations and revised them to reflect the change to a January 1, 2011 start date for reporting CO_2 and NO_X emissions.

C. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on mobile source were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Motor Vehicle and Engine Manufacturers.''

Comment: Light-duty vehicle manufacturers and their trade organizations raised several concerns about the timing and nature of the reporting requirements.

Response: We agree in part with these comments. However, more fundamentally, we have concluded that the likelihood of GHG emission regulations affecting light-duty vehicles (including light-duty trucks and medium-duty passenger vehicles) in the near future argues for consolidating any new GHG reporting requirements into that upcoming rule. Therefore, we have elected to not finalize the proposed requirements relating to these vehicles at this time, and expect to incorporate similar provisions in a proposed rule on GHG standards for light-duty vehicles in the near future.

Comment: Engine manufacturers and their trade organizations challenged the proposed rule in several ways. In general, they questioned the need for the data to be reported; expressed concern that the proposed timing of the requirements, especially for N_2O and CH_4, was too aggressive; and commented that the proposed test procedure for N_2O was not adequate.

Response: We still conclude that there is significant value to collecting CO_2, N_2O, and CH_4 emissions rate data on the broad range of mobile sources being produced. As stated earlier, the domestic and international attention to GHGs and their effects will only grow, and the ability for EPA and the public to understand and monitor emissions from mobile sources will be increasingly important as policies relating to GHGs are considered. Collecting emissions rate data from engine manufacturers on their new engines can improve modeling of emissions for the entire mobile source sector since current modeling relies on assumptions about N_2O and CH_4 emissions based on a limited number of field surveys. The data from this rule will also help EPA track emissions impacts from changes in technologies and policies over time.

For N_2O and CH_4, we agree that revisions in the proposed provisions are warranted. We have limited the reporting requirements for N_2O to engines equipped with NO_X aftertreatment technology as a way to reduce the reporting burden on engine manufacturers without significantly diminishing the amount of information we receive. As discussed earlier, emissions of N_2O are related to catalytic treatment of engine exhaust, specifically aftertreatment of NO_X emissions, and we have concluded that collecting N_2O emissions data from engines without NO_X aftertreatment technology would provide marginal value to the agency. We expanded the number of approved test methods for N_2O measurement since we learned from comments and our own technical research that our proposed test methods for N_2O were not appropriate for every foreseeable circumstance, including measurement of very low levels of N_2O. We also extended the lead time available to manufacturers before N_2O and CH_4 reporting is required. We are providing this flexibility based on our conclusion that we can reduce the burden of purchasing and installing the required CH_4 and N_2O emissions rate measurement equipment by extending the lead time, without significantly diminishing the amount of information we receive. Finally, as described above, the final rule includes an opportunity for a manufacturer to provide EPA with appropriate alternative information in lieu of N_2O and/or CH_4 testing.

Comment: States and environmental organizations were generally supportive of the proposed reporting requirements, although some argued for earlier implementation, in 2010.

Response: We believe that the lead times we are finalizing for each GHG and for each engine category represent the earliest feasible timing, taking into consideration existing test capabilities and past experience, or the lack thereof.

Comment: Aircraft engine manufacturers commented that reporting of CO_2 emissions from each mode of the LTO [30] cycle used in the emission certification test, as proposed, is acceptable as long as existing methods for CO_2 are retained. In particular, commenters noted that reporting would result in minimal

[30] Modes of the landing and takeoff cycle are taxi/idle, takeoff, climb out, and approach.

burden as long as CO_2 is calculated utilizing the engine fuel mass flow rate measurements, which are currently part of the test procedure requirements for the LTO cycle. However, an industry trade association expressed concern that reporting CO_2 from the LTO cycle is unjustified because LTO measurements do not include CO_2 emissions from an entire aircraft flight, which is affected by the propulsion system, drag, etc.

Response: We determined that calculating aircraft engine CO_2 emissions from fuel mass flow rate measurements is an appropriate method for reporting CO_2 emissions. Therefore, for turbofan and turbojet engines of rated output greater than 26.7 kilonewtons, we are finalizing that manufacturers report CO_2 separately for each mode of the LTO cycle by calculation of CO_2 from fuel mass flow rate measurements or, alternatively, according to the measurement criteria for CO_2 in Appendices 3 and 5 to ICAO Annex 16, volume II. Comprehensive and consistent reporting of LTO CO_2 emissions, along with knowledge of aircraft aerodynamic performance, will support modeling of full-flight CO_2 emissions and help us to better understand overall contributions to global warming from aircraft operations.

Comment: Aircraft engine manufacturers raised two major issues related to our proposed CH_4 reporting. First, in response to EPA's request for comment on the degree to which engine manufacturers now have the needed equipment in their certification test cells to measure CH_4, manufacturers replied that test stands are not currently equipped to measure CH_4, and thus, they would incur additional costs to measure CH_4. Second, manufacturers noted that aircraft jet turbine engines have been shown to be consumers of CH_4 from the ambient air during the dominant operating modes (CH_4 is emitted at aircraft engine idle operation, but at higher power modes aircraft engines usually consume CH_4. Over the range of engine operating modes—including cruise—aircraft engines are typically net consumers of CH_4).

Response: Given that aircraft engines are likely net consumers of CH_4 and that manufacturers do not currently collect CH_4 data as part of existing test procedures, we are not requiring CH_4 to be measured and reported at this time.

Comment: We received several responses to our request for comment on whether to require aircraft engine manufacturers to report NO_X emissions in the four LTO test modes and for the overall LTO cycle. Manufacturers commented that NO_X emissions do not need to be reported directly to EPA, since this information is already voluntarily reported to the International Civil Aviation Organization (ICAO) and provided to the Federal Aviation Administration (FAA), and redundancy of reporting is unnecessary. Environmental organizations commented that EPA should require manufacturers to report NO_X since they currently do not report the data to EPA. In addition, environmental organizations commented that NO_X at high altitude can contribute to global warming.

Response: In this final rule, we are requiring that engine manufacturers of turbofan and turbojet engines of rated output greater than 26.7 kilonewtons record and report NO_X emissions in the four LTO test modes and for the overall LTO cycles. As discussed in the proposal and earlier in this final rule, NO_X from aircraft have been shown to make a potential contribution to climate change at high altitude. As required in 40 CFR part 87, manufacturers must already measure and record NO_X emissions in each of the four LTO test modes in order to comply with the LTO NO_X emission standard (for the entire LTO cycle). These data are not currently reported to EPA for public consideration as is the case with all other mobile sources. Manufacturers voluntarily report the data to ICAO, but there is no assurance that EPA will receive this information. Likewise, the information provided to FAA is not readily accessible to EPA, and it is not of the detail provided to ICAO. Comprehensive and consistent reporting of LTO NO_X emissions rate data will support modeling of overall NO_X emissions from aircraft and help us to better understand overall contributions to global warming from aircraft operations.

V. Collection, Management, and Dissemination of GHG Emissions Data

This section of the preamble describes the general processes by which EPA intends to collect, manage, and disseminate data under the GHG reporting rule. Section A contains a brief description of the provisions in the final rule concerning these processes, and Section B summarizes public comments and responses on data collection, management, and dissemination.

Major changes since proposal include revisions in 40 CFR 98.4 that provide flexibility for designated representatives to delegate their responsibility to agents, and to submit revisions to the certificate of representation within 90 days of a change in owners or operators (rather than 30 days). In addition, the final rule includes a requirement that the designated representative submit the certificate of representation at least 60 days before the deadline of the facility or supplier's initial GHG report. The rationale for these and any other significant changes can be found in Section V.B of this preamble or in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Designated Representative, and Data Collection, Reporting, Management, and Dissemination.''

A. Summary of Data Collection, Management and Dissemination for the Final Rule

1. Designated Representatives, Alternate Designated Representatives, and Agents

Each covered facility and each supplier must identify one and only one designated representative who is responsible for certifying, signing, and submitting all submissions to EPA. A designated representative must certify and sign a submission, in accordance with the final rule, before it is considered a complete submission.

The designated representative also serves as a single point of contact for EPA to provide information about the program or a submission or to ask questions about a submission. Those facilities submitting any other emission report under 40 CFR part 75, for example, ARP facilities, must use the same designated representative for certifying, signing and submitting all submissions and reports under this rule.

Each covered facility or supplier may also identify one alternate designated representative to act in lieu of the designated representative. The alternate designated representative can perform the same duties as the designated representative, but the designated representative is responsible for ensuring the appropriate information is submitted to EPA by the timelines specified in the rule.

A designated representative or alternate designated representative may delegate the submission of information to one or more ''agents.'' The agent can make electronic submissions to EPA, but is not allowed to certify or sign a submission. By delegating to an agent the ability to make electronic submissions to EPA, a designated representative or alternate designated representative agrees that a submission to EPA by the agent is deemed to be a submission that is certified, signed, and submitted by such designated representative or alternate designated representative.

2. Certificate of Representation

A designated representative must submit a certificate of representation that identifies the owners and operators of the facility or supplier, the designated representative, any alternate designated representative, and other information as specified in 40 CFR 98.4. EPA will establish an electronic data reporting system that provides for the submission of initial, as well as subsequently signed, certificates of representation.

In order to ensure sufficient processing time before a facility or supplier's initial GHG report under this part, EPA is requiring that the designated representative submit a certificate of representation at least 60 days before the deadline for the initial GHG report.

3. Data Collection

Methods. If a reporting entity already reports GHG emissions data to an existing EPA program, the Agency will make efforts to minimize any additional burden on the reporter when developing the reporting system for the final rule. Some existing programs, however, have data collection and reporting requirements that are inconsistent with the requirements for the mandatory GHG reporting rule. When it is not feasible to adapt an existing program to collect the appropriate GHG data and supplemental data, EPA will require reporters to submit the data required by the mandatory GHG reporting rule to the new data reporting system for this rule. Such reporters would also continue to submit data to the existing reporting systems for other applicable programs as required by those programs.

Reporters may fall into one or more categories:

(1) Reporters that use existing data collection and reporting methods and will not be required to report separately to the new data reporting system for the GHG reporting rule.

(2) Reporters that use existing data collection and reporting methods but will be required to report the data separately to the new data reporting system for the GHG reporting rule.

(3) Reporters that are not currently required to collect and report GHG emissions data to EPA and will be required to report using the new data reporting system for the mandatory GHG reporting rule.

For categories (2) and (3), EPA is developing a new system for reporters to submit the required data. The detailed data elements that must be reported are specified in the rule. In general, reporters using this new system must report annually to the Agency according to the schedule specified in 40 CFR 98.3(b).

Data Submission. The Designated Representative (described in 40 CFR 98.4) must use an electronic signature device (for example, a personal identification number (PIN) or password) to submit a report. If the Designated Representative holds an electronic signature device that is currently used for valid electronic signatures accepted under another Agency program, we intend to design the new reporting system to also accept valid electronic signatures executed with that device where feasible. (*See* 40 CFR 3.10 and the definitions of ''electronic signature device'' and ''valid electronic signature'' under 40 CFR 3.3.)

Unique Identifiers for Facilities and Units. The Agency's reporting format for a given reporting year could make use of several ID codes—unique codes for a unit or facility. To ensure proper matching between databases, e.g., EPA-assigned facility ID codes and the Office of Regulatory Information Systems (ORIS) (DOE) ID code, and consistency from one reporting year to the next, we plan for the reporting system to provide each facility with a unique identification code to be specified by the Administrator.

Reporting Emissions in a Single Unit of Measure. To maintain consistency with existing State-level and Federal-level GHG programs in the U.S. and internationally, all emission measurements must be reported in the SI, also referred to as metric units. Data used in calculations and supplemental data for QA could still be submitted in English weights and measures (e.g., mmBtu/hr) but the specific units of measure must be included in the data submission. All emissions data must be submitted to the Agency in kg or metric tons per unit of time.

Conversion of Emissions to CO_2e. Reporters must submit the quantity of each applicable GHG emitted (or other metric such as quantities supplied for industrial GHG suppliers) in two forms. The data will be in the form of quantity of the gas emitted (e.g., metric tons of N_2O) per unit of time and CO_2e emissions per unit of time.

Delegation of Authority to State Agencies to Collect GHG Data. Reporters must submit the emissions data and supplemental data directly to EPA. At this time, EPA does not intend to delegate the authority to collect data to State or local agencies.

Submission Method. All entities covered by this rule must report in an electronic format to be specified by the Administrator. The electronic format, which will reflect the underlying electronic data reporting system, will be developed prior to the first reporting date. By specifying in the rule text the exact information that must be reported but not specifying the exact reporting format, EPA informs reporters about exactly what information they must report and has flexibility to modify the electronic reporting format and electronic data reporting system in a timely manner based on implementation experience and new technology. EPA has used this approach successfully in existing programs, such as the ARP and the Title VI Stratospheric Ozone Protection Program, facilitating the deployment of new reporting formats and reporting systems that take advantage of technologies such as, eXtensible Markup Language (XML), and reducing the burden on reporters and the Agency. The electronic reports submitted under this rule are subject to the provisions of 40 CFR part 3, specifying EPA systems to which electronic submissions must be made and the requirements for valid electronic signatures.

4. Data Management

QA Procedures. The new reporting system will include automated checks for data completeness, data quality, and data consistency. Such automated checks are used for many other Agency programs (e.g., ARP).

Providing Feedback to Reporters. EPA has established a variety of mechanisms under existing programs to provide feedback to reporters who have submitted data to the Agency. EPA will consider the approaches used by other programs (e.g., electronic confirmations, results of QA checks) and develop appropriate mechanisms to provide feedback to reporters for the GHG reporting rule when we develop the electronic data reporting system. Regardless of data collection system specifics, the goal is to ensure appropriate transparency and timeliness when providing feedback to reporters who submitted data.

5. Data Dissemination

Public Access to Emissions Data. The Agency plans to publish data submitted or collected under this rulemaking through EPA's Web site, reports, and other formats (e.g., XML), with the exception of any confidential business information (CBI) data. For further discussion of CBI, see Section II.R of this preamble.

EPA will disseminate data after the reporting deadline. The Agency recognizes the high level of public interest in this data and plans to disclose it in a timely manner, while also assuring completeness and accuracy.

Sharing Emission Data with Other Agencies. There are a growing number of programs at the State, Tribe, Territory, and local level that require emission sources in their respective jurisdictions to monitor and report GHG emissions. In order to be consistent with and supportive of these programs and to reduce burden on reporters and program agencies, EPA plans to share emissions data, with the exception of any CBI data, with relevant agencies or approved entities using, where practical, common data exchange standards and infrastructure.

B. Summary of Comments and Responses on Collection, Management, and Dissemination of GHG Emissions Data

This section contains a brief summary of major comments and responses. A large number of comments on data collection, management, and dissemination were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Designated Representative and Data Collection, Reporting, Management, and Dissemination.''

1. Designated Representatives, Alternative Designated Representatives, and Agents

Designated Representatives

Comment: Several commenters requested that EPA use the ARP definition for designated representatives to maintain consistency across the two EPA programs and provide more flexibility regarding who can be a designated representative. Other commenters requested that EPA use the responsible official definition from Title V or senior management official from TRI to maintain consistency with those programs. Other commenters raised concerns over the employment status of designated representatives.

Comment: A commenter noted that rule language was inconsistent in defining the relationships between designated representatives, facilities and suppliers, and owners and operators.

Response: EPA agrees that owners and operators should have more flexibility to identify a designated representative, including third-party representatives. EPA is striking the language requiring the designated representative to be a person responsible for the overall operation of the facility or supplier. Further, EPA is not requiring the use of a responsible official or senior management official because either approach would be more restrictive than the designated representative definition of the final rule. EPA believes that the proposed rule was neutral with respect to the employment status of the designated representative. The final rule provides flexibility for the owners and operators to choose any individual, employee or non-employee, to represent them. EPA modified the rule to clarify that each facility and each supplier shall have one and only one designated representative and that the designated representative must be authorized by binding agreement of the owners and operators.

Agents

Comment: Several commenters requested that EPA allow designated representatives and alternate designated representatives the option of delegating their responsibility to prepare and submit reports to EPA to a preparer or agent. Commenters also stated that the designated representative requirement is inconsistent with Title V reporting.

Response: EPA agrees that it is beneficial to give the designated representatives and alternate designated representatives flexibility concerning who prepares the reports that they are responsible for submitting. The final rule does not specify who must prepare reports, but only specifies who must certify, sign, and submit them. EPA also agrees that flexibility should be provided concerning who actually submits the reports, similar to the flexibility provided in the ARP. This flexibility was implied in the provision in the proposed rule that reports be submitted ''in a format specified by the Administrator,'' which format has included, in other programs such as the ARP, the ability to use agents. However, EPA decided to make this flexibility explicit by including in the rule provisions allowing and setting requirements for agents selected by designated representatives or alternate designated representatives. The structure of designated representative, alternate designated representative and agent fits a wide range of circumstances from large companies to small, including those accustomed to reporting under Title V.

Certification Statement

Comment: Several commenters described the self-certification procedures in the proposed rule as too restrictive or suggested that the rule should be consistent with requirements of the Title V or TRI program. For example, the rule's requirement that the designated representative certify that they have ''personally examined'' the data should be replaced by the Title V requirement that a responsible official certify that they have made a ''reasonable inquiry'' as to the accuracy of the data.

Response: EPA believes that the high level of public interest in the data collected under this rule, as well as its importance to future policy, warrants establishment, by rule pursuant to CAA Sections 114, 208, and 301(a)(1), of a high standard for data quality and consistency and a high level of accountability for reported data, which will help ensure that the data quality and consistency standard is met. The certification requirements set forth in this rule are similar to the ARP (Title IV). EPA has successfully implemented this approach in the ARP and found that it provides a high degree of both data quality and consistency and accountability.

2. Certificate of Representation

Comment: One commenter requested that EPA designate a deadline for the submission of the certificate of representation to ensure sufficient time to process the submissions.

Response: EPA agrees that an earlier deadline for submitting certificates of representation is advisable to provide additional lead time to process the certificates and, if necessary, verify identities and resolve issues. Because any delay in processing a certificate of representation could delay the submission of data, EPA is requiring that the designated representative submit the initial certificate of representation at least 60 days prior to the deadline for a facility or supplier's initial GHG report.

Comment: Several commenters noted that a certificate of representation for each facility and supplier is burdensome either due to timing with the annual report, the need to maintain current information, or ambiguities as to whether the certificate is complete. Commenters also requested that reporters be allowed more than 30 days to submit a revised certificate of representation in the event of a change in operators or owners.

Comment: Several commenters requested that EPA provide an electronic system for submitting and processing certificates of representation.

Response: EPA does not agree that certificates of representation are unnecessary or overly burdensome or that there should be any uncertainty as to whether a certificate of representation is complete. The information required on the certificate of representation is listed in the rule and should be well known to the owners and operators of the facility or supplier. It is the responsibility of the individual submitting the certificate to ensure its completeness. This certificate of representation has been used successfully for over a decade in the ARP.

To minimize burden, the electronic data reporting system will provide the means to electronically submit both the initial and any subsequent certificate of representation. EPA agrees that reporters should be allowed more time to update changes in owners or operators but does not agree that doing so in the annual report is sufficient. The designated representative is the primary point of contact between the owners and operators and the EPA. However, the owners and operators are ultimately responsible for compliance with the requirements of reporting rule, and it is therefore essential that the information in the certificate of representation be timely and accurate in the event EPA finds it necessary to contact the owners and operators of the facility or supplier during periods in between the submission dates of the annual reports, for example, to perform an audit. The final rule allows reporters up to 90 days to submit a revised certificate of representation when a change in owners or operators occurs. In addition, EPA modified both the owner definition and rule to clarify that the certificate of representation does not need to list persons whose legal or equitable title to or leasehold interest in a facility or supplier arises solely because they are limited partners in a partnership with legal or equitable title to, a leasehold interest in, or control of, the facility or supplier.

3. Data Collection Methods

Comment: Several commenters requested that EPA use current emission inventory reporting programs (e.g., NEI) to handle data collection or to sunset the GHG reporting rule, and instead use such programs, after five years.

Response: EPA is requiring electronic reports to be submitted directly to EPA using a new data reporting system for the GHG reporting rule. The rationale for the decision to report directly to EPA is contained in Sections II.N (emissions verification) and VI.B (compliance and enforcement) of this preamble. EPA recognizes the value of integrating the GHG data reported under this rule with other emission reporting programs. NEI, for example, plans to incorporate the GHG emissions data from this collection, as feasible.

Comment: Commenters requested that the design of the new data system be modeled on existing electronic reporting programs, incorporate measures to handle system errors, and provide opportunities for testing and user training.

Response: EPA agrees that a national electronic emissions database should be the basis for receiving GHG data, and that the ARP database provides a useful model for a future GHG emissions database. Data would be provided to EPA electronically to reduce the burden on the reporters and EPA, and to increase the accuracy of the reported emissions, among other reasons. The issue of transmission failures and transmission errors will be addressed in the development of the electronic reporting system. EPA agrees that is it important for data reporters to be able to confirm that their data were accepted by the system and to compare the data in the system to the data that they reported to ensure it was accurately incorporated into the database. The new data system will meet Agency requirements for security and hosting. EPA acknowledges comments supporting a ''user friendly'' reporting system. EPA plans to follow well known design practices within the constraints of security, accessibility and Agency design requirements.

EPA agrees with commenters on the need for testing and user training. We will continue the outreach effort undertaken during this rulemaking to encourage stakeholder participation in 'beta' testing and training opportunities.

Unique Identifiers for Facilities and Units

Comment: Several commenters requested that EPA assign and track corporate identifiers for reporting facilities to facilitate corporate-level analysis of emission data. Commenters also requested that EPA publish a list of identifiers for all EPA programs that a covered facility may report to.

Response: EPA is collecting owner and operator information through the Certificate of Representation (40 CFR 98.4). At this time, EPA is not proposing to assign unique identifiers to the owners and operators because of the complexity of ownership structures (including percentage shares of owners, subsidiaries, holding companies, and limited liability partnerships) that can be used in the multiplicity of industrial sectors required to report emission data under this rule. Although as explained earlier in the preamble, we are exploring options for adding additional data elements to the reports, such as name of parent company and NAICS code(s), to allow easier aggregation of facility-level data to the corporate level under this program. EPA expects to subject any additional requests to notice and comment rulemaking.

EPA's Facility Registry System (FRS) links EPA program identification numbers under a unique facility record. The FRS database is publicly available to queries from the EPA.GOV Web site under the Envirofacts Data Warehouse home page: *http://www.epa.gov/enviro/html/fii/fii_query_java.html*. Descriptive information about FRS can be found at: *http://www.epa.gov/enviro/html/fii/index.html*. FRS may be searched by program identification, facility name or geographic location. The Agency will continue to make FRS and all program identification numbers readily available and will include the facilities reporting under this rule in the FRS collection of program ID's once public release of the data is authorized.

Submission Method

Comment: Several commenters requested that EPA specify the format of the data collection methods and subject it to public comment before finalizing the rule. These commenters indicated that without the details of the data collection methods it was not possible to evaluate the GHG reporting rule, including implementation costs and reporting burden.

Response: The final rule requires reports to be submitted ''in a format specified by the Administrator.'' EPA is thereby retaining the flexibility to specify the electronic format, and the underlying electronic reporting system reflected in the format, after promulgation of this rule but well before the first reporting deadline and, if necessary, to change the electronic format and electronic reporting system based on implementation experience and new technology. Several other reporting programs (e.g., ARP) use a similar approach where the specific electronic reporting system is not included within the rule or subjected to formal notice and comment. The relevant subparts of the proposed GHG reporting rule specified the data elements that each entity must report, and therefore parties could evaluate the reporting burden and costs under the proposed rule and had an opportunity to comment on that aspect of the proposed rule. In addition, before specifying the electronic format and underlying electronic reporting system, EPA will conduct outreach and provide opportunities for stakeholder feedback on the specific reporting format and reporting system.

Comment: Several commenters requested that EPA provide alternative methods to report emission data, including paper submissions, scanned documents, and direct data upload.

Response: EPA is requiring electronic reporting of the GHG and supplemental data to increase the accuracy and timeliness of the reported emission data and is not providing options for paper or scanned GHG reports. Requiring electronic submission of data allows EPA to conduct electronic QA testing of all such data when it is received and to provide electronic feedback to the reporters almost instantaneously. This gives reporters the opportunity to correct any errors, or to provide explanations of potentially problematic data, within a short time frame, thereby increasing the accuracy and timeliness of the data. Moreover, electronically submitted data can be readily sorted and analyzed by EPA and members of the public. In contrast, submission of hardcopy data (whether in paper or scanned documents) would make audit and correction, as well as sorting and analysis, of the data much more cumbersome, inefficient, and time consuming. Indeed, particularly in light of the large number of facilities and suppliers that will be reporting and the large amounts of reported data that will be received as a result, the ability to audit and analyze the data received in hardcopy format would likely be significantly limited. This would adversely affect the usefulness, as well as the accuracy and timeliness of the data.

In requiring electronic data submission, EPA will provide a Web-based reporting system to guide reporters through the data entry, emission calculation, and submission process. This reporting system will conform to EPA information technology standards and 40 CFR part 3. In addition, EPA will provide a mechanism for reporters to submit data files directly to EPA using a standard format (e.g., XML) to be prescribed by the Administrator before the first reporting date. To reduce the burden on reporters and reduce errors, EPA will conduct outreach and training for reporters on the reporting format and underlying reporting systems. EPA will also provide a hotline to answer questions about the program and reporting format and reporting systems. EPA expects that most reporters affected by this rule are already familiar with Web-based or electronic reporting systems through other EPA programs.

Delegation of Authority to State Agencies To Collect GHG Data

Comment: Several commenters requested that EPA delegate rule implementation, including data collection, to State and local agencies. These commenters indicated that several States already have GHG reporting requirements and have systems in place to collect and verify this data, and suggested that delegation of the rule could help reduce inconsistency or duplication of effort between State programs and this Federal mandatory GHG reporting rule. Other commenters supported requiring facilities to submit data directly to EPA, without delegation of data collection to State and local agencies, in order to provide national consistency.

Response: EPA is requiring electronic reports to be submitted directly to EPA, and is not delegating data collection to State and local agencies. The rationale for this decision is provided in Section VI.B of this preamble.

5. Data Dissemination

Public Access to Emissions Data

Comment: Several commenters supported EPA's proposal to make the data submitted under the reporting rule available to the public. Some requested that data be published in real time, while others requested the data be released in a timely manner.

Response: With the exception of CBI, EPA intends to make data submitted under this program available to the public in a timely manner after the reports have been submitted and EPA has completed QA/QC of the data. To that end, EPA intends to establish a new reporting system that will accept electronic submissions of GHG emissions and supporting data and facilitate EPA's verification of the submissions. EPA plans to provide public access to the data by posting electronic data on a Web site in a timely manner after the reporting deadline. This level of transparency is important to public participation in future policy development and for building public confidence in the quality of the data collected.

Sharing Emissions Data With Other Agencies

Comment: Some commenters stressed that electronic data reporting systems need to be consistent and inter-operable and allow data exchange between TCR, State rules, NEI, ARP, other stakeholders and EPA.

Response: EPA will continue to coordinate with other Federal, State, and regional programs and will make efforts to facilitate data exchange when designing the data reporting system that will be used for the GHG reporting rule. EPA intends to employ inter-operable data exchange standards. EPA intends to design and manage the GHG data collection to take advantage of existing efforts on data exchange standards and to work with stakeholder groups to promote the easy exchange and sharing of the data collected under this rule. For example, EPA is extending the Consolidated Emissions Reporting Schema (CERS), currently in use by the EPA's NEI program, to support data reporting and publication under this rule. EPA also intends to use existing tools, such as FRS and SRS, to ensure data consistency.

To the extent possible, EPA will consider existing reporting systems and work with those programs and systems to develop a reporting scheme that facilitates data exchange. EPA anticipates that this coordination will reduce the burden of reporting for both reporters and government agencies. However, as explained in Section II.O of this preamble, the various reporting programs do not have identical data needs and requirements. Therefore, at this time, it is not possible for companies reporting under State and Federal rules and voluntary programs to file a single report that will satisfy all reporting requirements.

Comment: Commenters requested that the data system utilize common standards, such as XML and geographic identifiers, and provide descriptive text wherever codes or abbreviations are used.

Response: EPA agrees that publishing the results of this data collection using common, standards-based schemas and formats will promote the exchange of data between EPA, States and other entities. The published results will include the latitude and longitude of facilities as well as help text with definitions of codes and abbreviations.

VI. Compliance and Enforcement

This section of the preamble generally describes the compliance assistance and enforcement activities EPA intends to implement for the GHG reporting rule and summarizes public comments and responses on compliance assistance, role of the States, and enforcement.

A. Compliance and Enforcement Summary

1. Compliance Assistance

EPA plans to conduct an active outreach and technical assistance program following publication of the final rule. The primary audience is potentially affected industries. We intend to develop implementation and outreach materials and training to help potential reporters understand whether the rule applies to them and explain the reporting requirements and timetables. The program particularly will target industrial, commercial, and institutional sectors that do not routinely deal with air pollution regulations.

Compliance materials will be tailored to the needs of various sectors. These materials might include, for example, fact sheets, information sheets, plain English guides, frequently asked question and answer documents, applicability tools, monitoring and recordkeeping checklists, and training on rule requirements and the electronic reporting system. We also expect to implement a compliance assistance e-mail and telephone hotline for answering questions and providing technical assistance. Note that while EPA plans to issue compliance assistance materials, reporters should always consult the final rule to resolve any ambiguities or questions.

2. Role of the States

While EPA does not intend to formally delegate data collection and enforcement of the GHG reporting rule to State agencies, EPA will likely enlist State assistance, when it is available, for outreach and compliance assistance with the final rule. (However, State and local agencies will not be required to provide EPA any assistance with these activities, given State and local agency resource constraints and priorities.). State and local air pollution control agencies routinely interact with many of the sources that would report under this rule. Further, several States have experience implementing State mandatory GHG reporting and reduction programs. Therefore, we plan to work with those State and local agencies that are able to assist EPA to define their role in communicating the requirements of the rule and providing compliance assistance. In concert with their routine inspection and other compliance and enforcement activities for other CAA programs, State and local agencies may also be able to assist with educating facilities and assuring compliance at facilities subject to this rule.

3. Enforcement

Facilities or suppliers that fail to monitor or report GHG emissions, quantities supplied, or other data elements according to the requirements of the applicable rule subparts could potentially be subject to enforcement action by EPA under CAA sections 113 and 203–205. The CAA provides for several levels of enforcement that include administrative, civil, and criminal penalties. The CAA allows for injunctive relief to compel compliance and civil and administrative penalties of up to $37,500 per day per violation.[31]

Actions (or inactions) that could ultimately be considered violations include but are not limited to the following:

- Failure to report GHG emissions (for suppliers, the emissions that would result from combustion or use of the products they supply).
- Failure to collect data needed to calculate GHG emissions.
- Failure to continuously monitor and test as required. Note that merely filling in missing data as specified does not excuse a failure to perform the monitoring or testing.
- Failure to calculate GHG emissions according to the methodology(s) specified in the rule.
- Failure to keep required records needed to verify reported GHG emissions.
- Falsification of reports.

B. Summary of Public Comments and Responses on Compliance and Enforcement

This section contains a brief summary of major comments and responses. A large number of comments on compliance and enforcement were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Compliance and Enforcement.''

1. Role of States in Compliance and Enforcement

Comment: Several commenters requested that EPA delegate rule implementation, including data collection, emissions verification, and enforcement of the rule to State and local agencies. These commenters indicated that several States already have GHG reporting requirements and have systems in place to collect and verify these data, and they suggested that delegation of the rule could help reduce inconsistency or duplication of effort between State programs and this Federal mandatory GHG reporting rule. However the majority of commenters, including industry, environmental organizations, and many public citizens supported requiring facilities to submit data directly to EPA, without delegation of data collection or emissions verification to State and local agencies, in order to provide national consistency.

Response: Section 114(b) of the CAA allows EPA to delegate to States the authority to implement and enforce Federal rules. At this time, however, EPA does not propose to formally delegate implementation of the rule (such as data collection and enforcement activities) to State and local agencies, as discussed in Section II.O of this preamble. The goal of data collection under this rule is to establish a consistent, verified, national data set that is available to EPA, States, other agencies, policy makers, and the public for use in developing and implementing future GHG policies and reduction programs. To meet these data consistency and timeliness constraints, and to serve policy objectives, it is most efficient to have the data submitted directly into one central EPA system and have centralized emissions data verification. Direct reporting to EPA will also help us better understand and address common compliance problems that may arise from the GHG reporting rule.

EPA recognizes that several States already have mandatory GHG reporting programs that are broader in scope, in a more advanced state of development, and have different policy objectives than this rulemaking. These are important programs that not only led the way in reporting of GHG emissions before the Federal government acted but also have catalyzed important GHG reductions.

As discussed in Section II.O of this preamble, we are committed to working with States and other groups (e.g, TCR, Environmental Council of the States (ECOS)) to develop electronic reporting tools that can both collect and share data in an efficient and timely manner. At this time, EPA is in the process of developing the reporting format and tools and therefore has not specified the exact reporting format, other than it will be electronic, in order to maintain flexibility to modify the reporting format and tools in a timely manner. To the extent possible, EPA will work with existing reporting programs and systems to develop a reporting scheme that minimizes the burden on sources.

While EPA is not delegating authority to the States, we will work with States as we develop rule implementation plans to determine appropriate

[31] The Federal Civil Penalties Inflation Adjustment Act of 1990, Public Law 101–410, 104 Stat. 890, 28 U.S.C. 2461, note, as amended by Section 31001(s)(1) of the Debt Collection Improvement Act of 1996, Public Law 104–134, 110 Stat. 1321–373, April 26, 1996, requires EPA and other agencies to adjust the ordinary maximum penalty that it will apply when assessing a civil penalty for a violation. Accordingly, EPA has adjusted the CAA's provision in Section 113(b) and (d) specifying $25,000 per day of violation for civil violations to $37,500 per day of violation.

implementation roles, such as assisting with outreach efforts and site visits to audit facility reports. For related comments and responses, please see the following sections of this preamble: II.N (verification approach), II.O (role of States) and II.R (CBI).

2. Enforcement

Comment: Some commenters suggested that States should be allowed to participate in the enforcement of the GHG reporting rule, perhaps through delegated enforcement authority.

Response: EPA welcomes States' interest in helping EPA enforce this or any other Federal rule and we will work with States to determine appropriate roles as described above. We do not plan to delegate the enforcement of this rule in the same sense that we do under other CAA programs such as the NESHAP program in which, for example, notices may be sent only to the delegated States. If a State would like the authority to enforce this rule, then the State may adopt the provisions of this GHG reporting rule into State laws or regulations by reference. This would make the provisions enforceable as a matter of State law which can be enforced in a State court.

Comment: Some commenters stated that they should be able to petition EPA to enforce against violators where they have evidence of or suspect violations.

Response: EPA welcomes any tips from citizens about suspected violations of this or any rule through our tips Web site, *http://www.epa.gov/tips.* However, we are not including a formal petition process in the rule because such a process was not proposed. We do not favor a formal petition process because a formal petition is not necessary for us to investigate concerns raised by citizens and such a process might take extra time or divert resources from other priorities.

Comment: Some commenters stated that a flexible enforcement policy is needed. They noted that the proposed rule cited the CAA for the authority for the GHG reporting rule and stated that a violation of the reporting rule is a violation of the CAA and subject to maximum daily penalties allowed under the CAA. However, the commenters were concerned that the maximum penalty should not be applied in most cases and argued that there are many instances when a less severe action is appropriate.

Response: EPA agrees with the commenters that flexibility is needed in enforcing the rule. The penalty cited in the proposal preamble and rule is a statutory maximum, and would not be applied in every case. EPA's objective with the reporting rule is to collect accurate GHG data in a timely manner. In order to achieve that objective, EPA will generally work with sources that must submit GHG reports in order to facilitate compliance and provide the needed data to EPA. The CAA allows EPA discretion to pursue a variety of informal and formal actions in order to achieve compliance. While EPA is committed to working with reporters to ensure accuracy, this does not relieve reporters from their obligation to report data that are complete, accurate, and in accordance with the requirements of this rule.

In many instances, based on past enforcement experience, less punitive enforcement actions are exhausted before more punitive fines and penalties are imposed on a non-complying source. These less punitive actions may include a warning to the source that it is in non-compliance along with advice on what needs to be done to comply and a request for response from the facility. Initial actions may also include a formal legal notification from EPA that defines the violation, provides evidence, and requires (orders) corrective actions by specific dates. The EPA enforcement office always uses discretion and takes case-specific circumstances into account when determining the appropriate actions to address violations of CAA rules. We will continue to do so in enforcing the reporting rule, and we are not laying out a specific enforcement policy or hierarchy in order to maintain the necessary flexibility.

VII. Economic Impacts on the Rule

This section of the preamble examines the costs and economic impacts of the GHG reporting rule, including the estimated costs and benefits of the rule, and the estimated economic impacts of the rule on affected entities, including estimated impacts on small entities. Complete detail of the economic impacts of the final rule can be found in the text of the Regulatory Impact Analysis (RIA) for the final rule (EPA–HQ–OAR–2008–0508).

This section also contains a brief summary of major comments and responses. A large number of comments on economic impacts of the rule were received covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Cost and Economic Impacts of the Rule.''

A. How were compliance costs estimated?

1. Summary of Method Used To Estimate Compliance Costs

EPA estimated costs of complying with the rule for reporting process emissions of GHGs in each affected industrial facility, as well as emissions from stationary combustion sources at industrial facilities and other facilities, GHG and supply data from fuel suppliers and industrial gas suppliers, and GHG data for mobile sources. 2006 is the representative year of the analysis in that the annual costs were estimated using the 2006 population of emitting sources. EPA used available industry and EPA data to characterize conditions at affected sources. Incremental monitoring, recordkeeping, and reporting activities were then identified for each type of facility and the associated costs were estimated.

The costs of complying with the rule will vary from one facility to another, depending on the types of emissions, the number of affected sources at the facility, existing monitoring, recordkeeping, and reporting activities at the facility, etc. The costs include labor costs for performing the monitoring, recordkeeping, and reporting activities necessary to comply with the rule. For some facilities, costs include costs to monitor, record, and report emissions of GHGs from production processes and from stationary combustion units. For other facilities, the only emissions of GHGs are from stationary combustion. EPA's estimated costs of compliance are discussed in greater detail below:

Labor Costs. The costs of complying with and administering this rule include time of managers, technical, and administrative staff in both the private sector and the public sector. Staff hours are estimated for activities, including:

• *Monitoring (private):* Staff hours to operate and maintain emissions monitoring systems.

• *Reporting (private):* Staff hours to gather and process available data and reporting it to EPA through electronic systems.

• *Assuring and releasing data (public):* Staff hours to quality assure, analyze, and release reports.

Staff activities and associated labor costs will potentially vary over time. Thus, cost estimates are developed for start-up and first-time reporting, and subsequent reporting. Wage rates to monetize staff time are obtained from the Bureau of Labor Statistics (BLS).

Equipment Costs. Equipment costs include both the initial purchase price of monitoring equipment and any facility/process modification that may be required. For example, the cost estimation method for mobile sources involves upstream measurement by the vehicle manufacturers. This may require an upgrade to their test equipment and facility. Based on expert judgment, the engineering costs analyses annualized capital equipment costs with appropriate lifetime and interest rate assumptions. Cost recovery periods and interest rates vary by industry, but typically, one-time capital costs are amortized over a 10-year cost recovery period at a rate of seven percent.

2. Summary of Comments and Responses

Comment: A majority of the comments received on the compliance costs of the reporting rule focused on facility level costs for monitoring and reporting. Commenters noted that costs estimated for a representative facility may differ from actual facility level costs. Some commenters specifically referred to the costs associated with installing and maintaining capital equipment. Other commenters noted that some source categories had higher estimated compliance costs than others. Several commenters expressed confusion over how combustion related monitoring costs are added to process related monitoring costs.

Response: EPA recognizes that the costs presented for facilities represent costs that would be incurred by a representative facility, and may not reflect the costs that would be incurred by each individual facility in each industry because facilities affected by each subpart vary.

Nevertheless, after reviewing the comments received, EPA has determined that its analysis provides a reasonable characterization of costs for facilities affected by each subpart and that its documentation provides adequate documentation of how the costs were estimated. As described in the next section, EPA collected and evaluated cost data from multiple sources, and weighed the analysis prepared at proposal against the input received through public comments. In any analysis of this type, there will be variations in costs among facilities, and after thoroughly reviewing the available information, we have concluded that the costs developed for this rule appropriately reflect a ''representative facility'' in the sector.

The costs facing facilities in some sectors include not only process costs but additional costs associated with other subparts of the rule. While these costs are presented individually in Section 4 of the RIA for the final rule, where these conditions apply the costs are summed across applicable subparts and compared to revenues in the economic and small entity impact analyses.

B. What are the costs of the rule?

1. Summary of Costs

For the cost analysis, EPA gathered existing data from EPA, industry trade associations, States, and publicly available data sources (e.g., labor rates from the BLS) to characterize the processes, sources, sectors, facilities, and companies/entities affected. EPA also considered cost data submitted in public comments on the proposed rule, as further discussed in Section VII.B.2 of this preamble. Costs were estimated on a per entity basis and then weighted by the number of entities affected at the 25,000 metric tons CO_2e threshold.

To develop the costs for the rule, EPA estimated the number of affected facilities in each source category, the number and types of combustion units at each facility, the number and types of production processes that emit GHGs, process inputs and outputs (especially for monitoring procedures that involve a carbon mass balance), and the measurements that are already being made for reasons not associated with the rule (to allow only the incremental costs to be estimated). Many of the affected source categories, especially those that are the largest emitters of GHGs (e.g., electric utilities, industrial boilers, petroleum refineries, cement plants, iron and steel production, pulp and paper) are subject to national emission standards and we use data generated in the development of these standards to estimate the number of sources affected by the reporting rule.

Other components of the cost analysis included estimates of labor hours to perform specific activities, cost of labor, and cost of monitoring equipment. Estimates of labor hours were based on previous analyses of the costs of monitoring, reporting, and recordkeeping for other rules; information from the industry characterization on the number of units or process inputs and outputs to be monitored; and engineering judgment by industry and EPA industry experts and engineers. Labor costs were taken from the BLS and adjusted to account for overhead. Monitoring costs were generally based on cost algorithms or approaches that had been previously developed, reviewed, accepted as adequate, and used specifically to estimate the costs associated with various types of measurements and monitoring.

A detailed engineering analysis was conducted for each subpart of the rule to develop unique unit costs. This analysis is documented in the RIA for the final rule. The TSDs for each source category provide a discussion of the applicable measurement technologies and any existing programs and practices. The appropriate volume of ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments'' for each source category provide responses to any public comments on these source category engineering and cost analyses. Section 4 of the RIA for the final rule contains a description of the engineering cost analysis.

Table VII–1 of this preamble presents by subpart: The number of entities, the downstream emissions covered, the first year capital costs and the first year annualized costs of the rule. EPA estimates that the total national annualized cost for the first year is $132 million, and the total national annualized cost for subsequent years is $89 million (2006$). Of these costs, roughly 13 percent fall upon the public sector for program administration in the first year, while 87 percent fall upon the private sector. General stationary combustion sources, which are widely distributed throughout the economy, are estimated to incur approximately 26 percent of costs in the first year; other sectors incurring relatively large shares of costs are pulp and paper manufacturing (9 percent) and vehicle and engine manufacturers (9 percent).

The threshold, in large part, determines the number of entities required to report GHG emissions and hence the costs of the rule. The number of entities excluded increases with higher thresholds. Table VII–2 of this preamble provides the cost-effectiveness analysis for various thresholds examined. Two metrics are used to evaluate the cost-effectiveness of the emissions threshold. The first is the average cost per metric ton of emissions reported ($/metric ton CO_2e). The second metric for evaluating the threshold option is the incremental cost of reporting emissions. The incremental cost is calculated as the additional (incremental) cost per metric ton starting with the least stringent option and moving successively from one threshold option to the next. For more information about the first year capital costs (unamortized), project lifetime and the amortized (annualized) costs for each subpart, please refer to section 4 of the RIA for the final rule and the RIA cost appendix. Not all subparts require capital expenditures but those that do are clearly documented in the RIA for the final rule.

TABLE VII–1—ESTIMATED COVERED ENTITIES, EMISSIONS AND COSTS BY SUBPART (2006$)

Subpart	Number covered of entities	Downstream emissions		First year capital costs		First year total annualized costs [2]	
		(Million of $MtCO_2e$)	Share (percent)	(Million)	Share (percent)	(Million)	Share (percent)
Subpart A—General Provisions	0	0.0	0	$0.0	0	$0.0	0
Subpart B—Reserved	0	0.0	0	0.0	0	0.0	0
Subpart C—General Stationary Fuel Combustion Sources	3,000	220.0	6	10.5	27	25.8	20
Subpart D—Electricity Generation	1,108	2262.0	59	0.0	0	3.3	2
Subpart E—Adipic Acid Production	4	9.3	0	0.0	0	0.1	0
Subpart F—Aluminum Production	14	6.4	0	0.0	0	0.2	0
Subpart G—Ammonia Manufacturing	23	12.9	0	0.0	0	0.4	0
Subpart H—Cement Production	107	86.8	2	5.4	14	6.8	5
Subpart K—Ferroalloy Production	9	2.3	0	0.0	0	0.1	0
Subpart N—Glass Production	55	2.2	0	0.0	0	0.5	0
Subpart O—HCFC–22 Production	3	13.8	0	0.0	0	0.0	0
Subpart P—Hydrogen Production	41	15.0	0	0.0	0	0.4	0
Subpart Q—Iron and Steel Production	121	85.0	2	0.0	0	3.7	3
Subpart R—Lead Production	13	0.8	0	0.0	0	0.1	0
Subpart S—Lime Manufacturing	89	25.4	1	4.9	12	5.3	4
Subpart U—Miscellaneous Uses of Carbonates	0	0.0	0	0.0	0	0.0	0
Subpart V—Nitric Acid Production	45	17.7	0	0.2	1	0.9	1
Subpart X—Petrochemical Production	80	54.4	1	0.0	0	2.2	2
Subpart Y—Petroleum Refineries	150	204.7	5	1.6	4	6.1	5
Subpart Z—Phosphoric Acid Production	14	3.8	0	0.8	2	0.8	1
Subpart AA—Pulp and Paper Manufacturing	425	57.7	2	14.8	37	8.6	7
Subpart BB—Silicon Carbide Production	1	0.1	0	0.0	0	0.0	0
Subpart CC—Soda Ash Manufacturing	5	3.1	0	0.0	0	0.1	0
Subpart EE—Titanium Dioxide Production	8	3.7	0	0.0	0	0.1	0
Subpart GG—Zinc Production	5	0.8	0	0.0	0	0.1	0
Subpart HH—Landfills	2,551	91.1	2	1.3	3	12.4	9
Subpart JJ—Manure Management	107	4.5	0	0.0	0	0.3	0
Subpart LL -Suppliers of Coal & Subpart MM—Suppliers of Petroleum Products	315	0.0	0	0.0	0	3.7	3
Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids	1,502	0.0	0	0.0	0	6.8	5
Subpart OO—Suppliers of Industrial Greenhouse Gases	167	643.4	17	0.0	0	0.5	0
Subpart PP—Suppliers of Carbon Dioxide (CO_2)	13	0.0	0	0.0	0	0.0	0
Subpart QQ—Motor Vehicle and Engine Manufacturers	317	NA	NA	0.0	0	8.6	7
Coverage Determination Costs for Non-Reporters	NA	NA	NA	NA	NA	17.2	13
Private Sector, Total	10,152	3,827	100	39.6	100	115.0	87
Public Sector, Total	NA	NA	NA	NA	NA	17.0	13
Total	10,152	3,827	100	39.6	100	132.0	100

[1] Emissions from upstream facilities are excluded from these estimates to avoid double counting.
[2] Total costs include labor and capital costs incurred in the first year. Capital Costs are annualized using appropriate equipment lifetime and interest rate (see additional details in section 4 of the RIA for the final rule).

TABLE VII–2—THRESHOLD COST-EFFECTIVENESS ANALYSIS (2006$)

Threshold (tons CO_2e)	Facilities required to report	Total costs (million $2006)	Downstream emissions reported ($MtCO_2e$/year)	Percentage of total downstream emissions reported (percent)	Average reporting cost ($2006/ton)	Incremental cost ($/metric ton)
100,000	6,269	$89	3,738	53	$0.02	
25,000	10,152	132	3,827	54	0.03	0.49
10,000	16,718	160	3,861	55	0.04	0.83
1,000	54,229	398	3,926	56	0.10	3.67

* Cost per metric ton relative to the selected option.
Note: Does not include emissions for Motor Vehicle and Engine Manufacturers (Subpart QQ).

Table VII–3 of this preamble presents costs broken out by upstream and downstream sources. Upstream sources include the fuel suppliers and industrial GHG suppliers. Downstream suppliers include combustion sources, industrial processes, and biological processes. Most upstream facilities (e.g., refineries) are also direct emitters of GHGs and are included in the downstream side of the table. As shown in Table VII–3 of this preamble, over 99 percent of industrial processes emissions are covered at the 25,000 metric tons CO_2e threshold for a cost of approximately $36 million. However, it should be noted that due to data limitations the coverage estimates for upstream and downstream source categories are approximations.

TABLE VII–3—UPSTREAM VERSUS DOWNSTREAM COSTS

Upstream [1]				Downstream [2 3 4]			
Source category	No. of reporters	Emissions coverage (%) [10]	First year cost (millions)	Source category	No. of reporters [2]	Emissions coverage [3 7 10] (%)	First year cost [3] (millions)
Coal Supply	0	0	$0.00	Coal [5 6] Combustion	N/A	99.0	N/A
Petroleum Supply	315	100	3.66	Petroleum [5] Combustion [9]	N/A	20.0	N/A
Natural Gas Supply	1,502	68	6.76	Natural Gas [5] Combustion	N/A	23.0	N/A
				Sub Total Combustion	4,108	N/A	$29.04
Industrial Gas Supply	167	100	0.52	Industrial Gas Consumption	17	14	0.24
				Industrial Processes	1,068	99.6	36.2
				Fugitive Emissions (coal, oil and gas).	0	0	0.00
				Biological Processes	2,658	58	12.77
				Vehicle [8] and Engine Manufacturers.	317	80	8.61

Notes

[1] Most upstream facilities (e.g., refineries) are also direct emitters of greenhouse gases, and are included in the downstream side of the table.

[2] Estimating the total number of downstream reporters by summing the rows will result in double-counting because some facilities are included in more than one row due to multiple types of emissions (e.g., facilities that burn fossil fuel and have process/fugitive/biological emissions will be included in each downstream category).

[3] The coverage and costs for downstream reporters apply to the specific source category, i.e., the fixed costs are not ''double-counted'' in both stationary combustion and industrial processes for the same facility.

[4] The thresholds used to determine covered facilities are additive, i.e., all of the source categories located at a facility (e.g., stationary combustion and process emissions) are added together to determine whether a facility meets the threshold (e.g., 25,000 metric tons of CO_2e/yr).

[5] Estimates for the number of reporters and total cost for downstream stationary combustion do not distinguish between fuels. National level data on the number of reporters could be estimated. However, estimating the number of reporters by fuel was not possible because a single facility can combust multiple fuels. For these reasons there is not a reliable estimate of the total of the emissions coverage from the downstream stationary combustion.

[6] Approximately 90 percent of downstream coal combustion emissions are already reported to EPA through requirements for electricity generating units under the ARP.

[7] Due to data limitations, the coverage for downstream sources for fuel and industrial gas consumption in this table does not take into account thresholds. Assuming full emissions coverage for each source slightly over-states the actual coverage that will result from this rule. To estimate total emissions coverage downstream, by fuel, we added total emissions resulting from the respective fuel combusted in the industrial and electricity generation sectors and divided that by total national GHG emissions from the combustion of that fuel.

[8] The percent of coverage here is percentage of total heavy-duty highway vehicles and engines, motorcycles, and nonroad engine sales covered by manufacturer reporting in this proposal rather than emissions coverage. The ''threshold'' for mobile sources is based on manufacturer size rather than total emissions. In this rule, all heavy-duty highway and nonroad vehicle and engine manufacturers, except those that meet EPA's definition of ''small business'' or ''small volume manufacturers'', would report emissions rates of CO_2, CH_4, and N_2O from the products they supply. This source category is neither upstream nor downstream, but is included in the downstream column for illustrative purposes.

[9] The emissions coverage for petroleum combustion includes combustion of fuel by transportation sources as well as other uses of petroleum (e.g., home heating oil). It cannot be broken out by transportation versus other uses as there are difficulties associated with tracking which products from petroleum refiners are used for transportation fuel and which were not. We know that although refiners make these designations for the products leaving their gate, the actual end use can and does change in the market. For example, designated transportation fuel can always be used as home heating oil.

[10] Emissions coverage from the combustion of fossil fuels upstream represents CO_2 emissions only. It is not possible to estimate nitrous oxide and methane emissions without knowing where and how the fuel is combusted. In the case of downstream emissions from stationary combustion of fossil fuels, nitrous oxide and methane emissions are included in the emissions coverage estimate. They represent approximately one percent of the total emissions.

2. Summary of Comments and Responses

Comment: EPA received comments on source specific cost data reflected in the engineering cost analysis presented in section 4 of the RIA for the proposed rule (EPA–HQ–OAR–2008–0318–002). Some commenters asked EPA to not overly burden entities that may be required to report and to balance reporting costs with the need for accurate reporting of GHG emissions.

Additional comments received questioned EPA's estimate of the costs associated with third party verification, as well as the estimated burden to the Federal government for self certification with EPA verification.

Response: EPA considered all relevant comments regarding source specific cost data developed in the engineering cost analysis and used in the RIA for the proposed rule. In some cases, we revised our cost estimates, and in some cases we revised monitoring and reporting requirements in ways which reduced burden. Please see source specific comments and responses in Section III of this preamble and the relevant volume of ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments''.

EPA believes the selected option for the mandatory GHG reporting rule strikes a balance between impacts on small entities, consistency with other programs, costs incurred by the reporting entities, and emissions coverage. Section 5 of the RIA for the final rule provides cost comparisons for each alternative evaluated.

In evaluating the costs of self certification with EPA verification and third party verification, EPA conducted a thorough review of relevant cost information available. EPA also considered cost data submitted in public comments on the proposed rule. EPA's review of verification costs included examining estimated Agency costs for other EPA based reporting programs, as well as a study conducted by the California Air Resources Board (CARB). The results of EPA's review of verification costs can be found in the Memo on Verification Costs in the docket. The final rule retains self-certification with EPA verification. EPA's estimated cost for verification activities is $7 million per year. Additional comments and responses on third party verification can be found in Section II.N of this preamble. Section 5.1.6 of the RIA for the final rule contains the full economic analysis of verification costs and options.

C. What are the economic impacts of the rule?

1. Summary of Economic Impacts

EPA prepared an economic impact analysis to evaluate the impacts of the rule on affected industries and economic sectors. In evaluating the various reporting options considered, EPA conducted a cost-effectiveness analysis, comparing the cost per metric ton of GHG emissions across reporting options. EPA used this information to identify the preferred options described in today's rule.

To estimate the economic impacts of the rule, EPA first conducted a screening assessment, comparing the estimated total annualized compliance costs by industry, where industry is defined in terms of North American Industry Classification System (NAICS) code, with industry average revenues. Overall national costs of the rule are significant because there is a large number of affected entities, but per-entity costs are low. Average cost-to-sales ratios for establishments in affected NAICS codes are uniformly less than 0.8 percent.

These low average cost-to-sales ratios indicate that the rule is unlikely to result in significant changes in firms' production decisions or other behavioral changes, and thus unlikely to result in significant changes in prices or quantities in affected markets. Thus, EPA followed its *Guidelines for Preparing Economic Analyses* (EPA, 2002, p.124–125) and used the engineering cost estimates to measure the social cost of the rule, rather than modeling market responses and using the resulting measures of social cost. Table VII–4 of this preamble summarizes cost-to-sales ratios for affected industries.

TABLE VII–4—ESTIMATED COST-TO-SALES RATIOS FOR AFFECTED ENTITIES

NAICS	NAICS description	Average cost per entity ($1,000/entity)	Average entity cost-to-sales ratio [1] (percent)
211	Oil and Gas Extraction	$2	<0.1
221	SF6 from Electrical Systems	5	<0.1
322	Pulp & Paper Manufacturing	20	<0.1
324	Petroleum and Coal Products	21	<0.1
325	Chemical Manufacturing	14	<0.1
327	Cement & Other Mineral Production	50	0.8
331	Primary Metal Manufacturing	26	<0.1
486	Oil & Natural Gas Transportation	4	<0.1
562	Waste Management and Remediation Services	5	0.2
325199	Adipic Acid	24	<0.1
325311	Ammonia	17	<0.1
327310	Cement	63	0.2
331112	Ferroalloys	9	<0.1
3272	Glass	8	<0.1
325120	Hydrogen Production	3	<0.1
331112	Iron and Steel	30	<0.1
3314	Lead Production	10	<0.1
327410	Lime Manufacturing	60	0.4
325311	Nitric Acid	20	<0.1
324110	Petrochemical	27	<0.1
325312	Phosphoric Acid	60	<0.1
322110	Pulp and Paper	20	<0.1
324110	Refineries	41	<0.1
327910	Silicon Carbide	10	<0.1
3251	Soda Ash Manufacturing	16	<0.1
325188	Titanium Dioxide	10	<0.1
3314	Zinc Production	13	<0.1

[1] This ratio reflects first year costs. Subsequent year costs will be slightly lower because they do not include initial start-up activities.

2. Summary of Comments and Responses

Comment: EPA received a number of comments on the overall economic impacts of the proposed rule. Some commenters stated that the economic impacts are understated, as costs will not be passed on to consumers from reporters. Other commenters stated that large increases in operating costs resulting from mandatory reporting of GHGs would lead facilities to close or move offshore.

Response: As described previously, EPA conducted a thorough analysis of available information and reviewed comments submitted on this issue, and we have determined that this analysis provides a reasonable characterization of costs for facilities in each subpart and that the documentation provides adequate explanation of how the costs were estimated. Our economic impact analysis has been conducted without taking into account the fact that some share of costs may be passed on to customers of each affected sector. Instead, facilities' annualized costs were compared to sales for entities in the sector, overall and for small entities. Even when all costs are absorbed by the facility, the costs represent less than one percent of sales and thus are not expected to result in significant hardship for affected firms.

D. What are the impacts of the rule on small businesses?

1. Summary of Impacts on Small Businesses

As required by the RFA and Small Business Regulatory Enforcement and Fairness ACT (SBREFA), EPA assessed the potential impacts of the rule on small entities (small businesses, governments, and non-profit organizations). (*See* Section VIII.C of this preamble for definitions of small entities.)

EPA has determined the selected thresholds maximize the rule coverage with 81 to 86 percent of U.S. GHG emissions reported by approximately 10,152 reporters, while keeping reporting burden to a minimum and excluding small emitters. Furthermore, many industry stakeholders that EPA met with expressed support for a 25,000 metric ton CO_2e threshold because it sufficiently captures the majority of GHG emissions in the U.S., while excluding smaller facilities and sources. For small facilities that are covered by the rule, EPA has included simplified emission estimation methods in the rule where feasible (e.g., stationary combustion equipment under a certain rating can use a simplified calculation approach as opposed to more rigorous direct monitoring) to keep the burden of reporting as low as possible. We received many comments related to monitoring and reporting requirements in specific source categories, and made many changes in response to reduce burden on reporters. For information on these issues, refer to the discussion of each source category in this preamble and the relevant volume of ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments.'' For further detail on the rationale for excluding small entities through threshold selection please see the Thresholds TSD (EPA–HQ–OAR–2008–0508–046) and Section III.C.3 of this preamble.

EPA conducted a screening assessment comparing compliance costs for affected industry sectors to industry-specific receipts data for establishments owned by small businesses. This ratio constitutes a ''sales'' test that computes the annualized compliance costs of this rule as a percentage of sales and determines whether the ratio exceeds some level (e.g., one percent or three percent).[32] The cost-to-sales ratios were constructed at the establishment level (average reporting program costs per establishment/average establishment receipts) for several business size ranges. This allowed EPA to account for receipt differences between establishments owned by large and small businesses and differences in small business definitions across affected industries. The results of the screening assessment are shown in Table VII–5 of this preamble.

TABLE VII–5—ESTIMATED COST-TO-SALES RATIOS BY INDUSTRY AND ENTERPRISE SIZE [a]

Industry	NAICS	NAICS description	SBA size standard (effective March 11, 2008)	Average cost per entity ($1,000/entity)	All enterprises (percent)	Owned by enterprises with:					
						<20 employees [f] (percent)	20 to 99 employees (percent)	100 to 499 employees (percent)	500 to 749 employees (percent)	750 to 999 employees (percent)	1,000 to 1,499 employees (percent)
Oil and Gas Extraction.	211	Oil & gas extraction.	500	$2	0.0	0.2	0.0	0.0	0.0	0.0	0.0
SF6 from Electrical Systems.	221	Utilities	([b])	5	0.0	0.2	0.0	0.0	0.0	0.0	0.0
Pulp & Paper Manufacturing.	322	Paper mfg	500 to 750	20	0.1	1.2	0.2	0.1	0.0	0.0	0.0
Petroleum and Coal Products.	324	Petroleum & coal products mfg.	([c])	21	0.0	0.6	0.1	0.1	0.0	0.2	0.0
Chemical Manufacturing.	325	Chemical mfg	500 to 1,000	14	0.0	0.7	0.1	0.0	0.0	0.0	0.0
Cement & Other Mineral Production.	327	Nonmetallic mineral product mfg.	500 to 1,000	50	0.8	4.8	0.9	0.5	0.4	0.5	0.4
Primary Metal Manufacturing.	331	Primary metal mfg	500 to 1,000	26	0.1	2.1	0.3	0.1	0.1	0.0	0.0
Oil & Natural Gas Transportation.	486	Pipeline transportation.	([d])	4	0.0	0.0	0.2	0.1	NA	NA	NA
Waste Management and Remediation Services.	562	Waste management & remediation services.	([e])	5	0.2	0.7	0.1	0.1	0.0	0.0	0.0
Adipic Acid	325199	All other basic organic chemical mfg.	1,000	24	0.0	0.9	0.3	0.1	NA	0.0	NA
Ammonia	325311	Nitrogenous fertilizer mfg.	1,000	17	0.1	0.9	0.5	NA	NA	NA	NA
Cement	327310	Cement mfg	750	63	0.2	2.0	1.5	0.3	NA	NA	0.1
Ferroalloys	331112	Electrometallurgical ferroalloy product mfg.	750	9	0.0	NA	NA	NA	NA	NA	NA
Glass	3272	Glass & glass product mfg.	500 to 1,000	8	0.1	1.4	0.2	0.0	0.0	0.1	0.0
Hydrogen Production.	325120	Industrial gas mfg	1,000	3	0.0	0.6	0.0	0.1	NA	NA	NA

[32] EPA's RFA guidance for rule writers suggests the ''sales'' test continues to be the preferred quantitative metric for economic impact screening analysis.

TABLE VII–5—ESTIMATED COST-TO-SALES RATIOS BY INDUSTRY AND ENTERPRISE SIZE [a]—Continued

Industry	NAICS	NAICS description	SBA size standard (effective March 11, 2008)	Average cost per entity ($1,000/entity)	All enterprises (percent)	Owned by enterprises with:					
						<20 employees [f] (percent)	20 to 99 employees (percent)	100 to 499 employees (percent)	500 to 749 employees (percent)	750 to 999 employees (percent)	1,000 to 1,499 employees (percent)
Iron and Steel	331112	Electrometallurgical ferroalloy product mfg.	750	30	0.1	NA	NA	NA	NA	NA	NA
Lead Production	3314	Nonferrous metal (except aluminum) production & processing.	750 to 1,000	10	0.0	0.6	0.1	0.0	NA	NA	0.0
Lime Manufacturing.	327410	Lime mfg	500	60	0.4	16.5	1.2	NA	NA	NA	NA
Nitric Acid	325311	Nitrogenous fertilizer mfg.	1,000	20	0.1	1.0	0.6	NA	NA	NA	NA
Petrochemical	324110	Petroleum refineries.	(c)	27	0.0	0.4	0.0	0.0	0.0	NA	NA
Phosphoric Acid	325312	Phosphatic fertilizer mfg.	500	60	0.1	10.1	NA	NA	NA	NA	NA
Pulp and Paper	322110	Pulp mills	750	20	0.0	1.4	NA	NA	NA	NA	NA
Refineries	324110	Petroleum refineries.	(c)	41	0.0	0.6	0.0	0.0	0.0	NA	NA
Silicon Carbide	327910	Abrasive product mfg.	500	10	0.1	0.8	0.2	0.1	NA	NA	NA
Soda Ash Manufacturing.	3251	Basic chemical mfg.	500 to 1,000	16	0.0	0.5	0.1	0.0	0.0	0.0	0.0
Titanium Dioxide	325188	All other basic inorganic chemical mfg.	1,000	10	0.0	0.7	0.4	0.1	NA	NA	NA
Zinc Production	3314	Nonferrous metal (except aluminum) production & processing.	750 to 1,000	13	0.1	0.9	0.1	0.0	NA	NA	0.0

[a] The Census Bureau defines an enterprise as a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments.

Since the SBA's business size definitions (*http://www.sba.gov/size*) apply to an establishment's ultimate parent company, we assume in this analysis that the enterprise definition above is consistent with the concept of ultimate parent company that is typically used for SBREFA screening analyses.

[b] NAICS codes 221111, 221112, 221113, 221119, 221121, 221122—A firm is small if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed four million MW hours.

[c] 500 to 1,500. For NAICS code 324110—For purposes of Government procurement, the petroleum refiner must be a concern that has no more than 1,500 employees nor more than 125,000 barrels per calendar day total Operable Atmospheric Crude Oil Distillation capacity. Capacity includes owned or leased facilities as well as facilities under a processing agreement or an arrangement such as an exchange agreement or a throughput. The total product to be delivered under the contract must be at least 90 percent refined by the successful bidder from either crude oil or bona fide feedstocks.

[d] NAICS codes 486110 = 1,500 employees; NAICS 486210 = $6.5 million annual receipts; NAICS 486910 = 1,500 employees; and NAICS 486990 = $11.5 million annual receipts.

[e] Ranges from $6.5 to $13.0 million annual receipts; Environmental Remediation services has a 500 employee definition and the following criteria. NAICS 562910—Environmental Remediation Services:

(1) For SBA assistance as a small business concern in the industry of Environmental Remediation Services, other than for Government procurement, a concern must be engaged primarily in furnishing a range of services for the remediation of a contaminated environment to an acceptable condition including, but not limited to, preliminary assessment, site inspection, testing, remedial investigation, feasibility studies, remedial design, containment, remedial action, removal of contaminated materials, storage of contaminated materials and security and site closeouts. If one of such activities accounts for 50 percent or more of a concern's total revenues, employees, or other related factors, the concern's primary industry is that of the particular industry and not the Environmental Remediation Services Industry.

(2) For purposes of classifying a Government procurement as Environmental Remediation Services, the general purpose of the procurement must be to restore a contaminated environment and also the procurement must be composed of activities in three or more separate industries with separate NAICS codes or, in some instances (e.g., engineering), smaller sub-components of NAICS codes with separate, distinct size standards. These activities may include, but are not limited to, separate activities in industries such as: Heavy Construction; Special Trade Construction; Engineering Services; Architectural Services; Management Services; Refuse Systems; Sanitary Services, Not Elsewhere Classified; Local Trucking Without Storage; Testing Laboratories; and Commercial, Physical and Biological Research. If any activity in the procurement can be identified with a separate NAICS code, or component of a code with a separate distinct size standard, and that industry accounts for 50 percent or more of the value of the entire procurement, then the proper size standard is the one for that particular industry, and not the Environmental Remediation Service size standard.

[f] Given the Agency's selected thresholds, enterprises with fewer than 20 employees are likely to be excluded from the reporting program.

NA: Not available. SUSB did not report the data necessary to calculate this ratio.

EPA was not able to calculate a cost-to-sales ratio for manure management (NAICS 112) as Statistics of U.S. Businesses ([SUSB]SBA, 2008a) data do not provide establishment information for agricultural NAICS codes (e.g., NAICS 112 which covers manure management). EPA estimates that the total first year reporting costs for the entire manure management industry to be $0.3 million with an average cost per ton of CO_2e reported of $0.07.

As shown, the cost-to-sales ratios are less than one percent for establishments owned by small businesses that EPA considers most likely to be covered by the reporting program (e.g., establishments owned by businesses with 20 or more employees).

EPA acknowledges that several enterprise categories have ratios that exceed this threshold (e.g., enterprise with one to 20 employees). EPA took a conservative approach with the model entity analysis. Although the appropriate SBA size definition should be applied at the parent company (enterprise) level, data limitations allowed us only to compute and compare ratios for a model establishment within several enterprise size ranges. To assess the likelihood that these small businesses will be covered by the rule, we performed several case studies for manufacturing industries where the cost-to-receipt ratio exceeded one percent. For each industry, we used and applied emission data from a recent study examining emission thresholds [33]. This study provides industry-average CO_2 emission rates (e.g., tons per employee) for these manufacturing industries.

The case studies showed two industries (cement and lime manufacturing) where emission rates suggest small businesses of this employment size could potentially be covered by the rule. As a result, EPA examined corporate structures and ultimate parent companies were identified using industry surveys and the latest private databases such as Dun & Bradstreet. The results of this analysis show cost to sales ratios below one percent.

For the other enterprise categories identified with ratios between one percent and three percent EPA examined industry specific bottom up databases and previous industry specific studies to ensure that no entities with less than 20 employees are captured under the rule.

Although this rule will not have a significant economic impact on a substantial number of small entities, the Agency nonetheless tried to reduce the impact of this rule on small entities, including seeking input from a wide range of private- and public-sector stakeholders. When developing the rule, the Agency took special steps to ensure that the burdens imposed on small entities were minimal. The Agency conducted several meetings with industry trade associations to discuss regulatory options and the corresponding burden on industry, such as recordkeeping and reporting. The Agency investigated alternative thresholds and analyzed the marginal costs associated with requiring smaller entities with lower emissions to report. The Agency also recommended a hybrid method for reporting, which provides flexibility to entities and helps minimize reporting costs.

Additional analysis for a model small government also showed that the annualized reporting program costs were less than one percent of revenue. These impacts are likely representative of ratios in industries where data limitations do not allow EPA to compute sales tests (e.g., general stationary combustion and manure management). Potential impacts of the rule on small governments were assessed separately from impacts on Federal Agencies. Small governments and small non-profit organizations may be affected if they own affected stationary combustion sources, landfills, or natural gas suppliers. However, the estimated costs under the rule are estimated to be small enough that no small government or small non-profit is estimated to incur significant impacts. For example, from the 2002 Census (in $2006), revenues for small governments (counties and municipalities) with populations fewer than 10,000 are $3 million, and revenues for local governments with populations less than 50,000 is $7 million. As an upper bound estimate, summing typical per-respondent costs of combustion plus landfills plus natural gas suppliers yields a cost of approximately $18,000 per local government. Thus, for the smallest group of local governments (<10,000 people), cost-to-revenue ratio is 0.7 percent. For the larger group of governments less than 50,000, the cost-to-revenue ratio is 0.2 percent.

2. Summary of Comments and Responses

Comment: Comments received on small business impacts focused on the economic burden to small businesses for compliance with mandatory GHG reporting. One commenter noted that lowering the reporting threshold below the proposed 25,000 metric ton CO_2e level would disproportionately affect small businesses. Another commenter stated that small businesses are not well equipped to handle detailed requirements for reporting and that the proposed rule would impose a large burden for monitoring, recordkeeping, and reporting activities.

Additional comments received requested that EPA establish a SBREFA process to investigate the impacts that the proposed rule would have on small businesses.

Response: As summarized above, EPA investigated alternative thresholds and analyzed the marginal costs associated with requiring smaller entities with lower emissions to report. EPA recognized the additional burden placed on small entities at lower thresholds, and had retained the hybrid method for reporting that includes a 25,000 metric ton CO_2e level threshold. Under this threshold, EPA has assessed the economic impact of the final rule on small entities and concluded that this action will not have a significant economic impact on a substantial number of small entities.

For this reason, EPA did not establish a SBREFA panel process for the rulemaking. The summary of the factual basis for the certification is provided in the preamble for the rule. Complete documentation of the analysis can be found in Section 5.2 of the RIA for the final rule.

E. What are the benefits of the rule for society?

1. Summary of Method Used To Estimate Compliance Costs

EPA examined the potential benefits of the GHG reporting rule. The benefits of a reporting system are based on their relevance to policy making, transparency issues, and market efficiency. Benefits are very difficult to quantify and monetize. Instead of a quantitative analysis of the benefits, EPA conducted a systematic literature review of existing studies including government, consulting, and scholarly reports.

A mandatory reporting system will benefit the public by increased transparency of facility emissions data. Transparent, public data on emissions allows for accountability of polluters to the public stakeholders who bear the cost of the pollution. Citizens, community groups, and labor unions have made use of data from Pollutant Release and Transfer Registers to negotiate directly with polluters to lower emissions, circumventing greater government regulation. Publicly available emissions data also will allow individuals to alter their consumption habits based on the GHG emissions of producers.

The greatest benefit of mandatory reporting of industry GHG emissions to government will be realized in developing future GHG policies. For example, in the EU's Emissions Trading System, a lack of accurate monitoring at the facility level before establishing CO_2 allowance permits resulted in allocation of permits for emissions levels an average of 15 percent above actual levels in every country except the United Kingdom.

Benefits to industry of GHG emissions monitoring include the value of having independent, verifiable data to present to the public to demonstrate appropriate environmental stewardship, and a better understanding of their emission levels and sources to identify opportunities to reduce emissions. Such monitoring allows for inclusion of standardized GHG data into environmental management systems, providing the necessary information to achieve and

[33] Nicholas Institute for Environmental Policy Solutions, Duke University. 2008. Size Thresholds for Greenhouse Gas Regulation: Who Would be Affected by a 10,000-ton CO_2 Emissions Rule? Available at: *http://www.nicholas.duke.edu/institute/10Kton.pdf.*

disseminate their environmental achievements.

Standardization will also be a benefit to industry, once facilities invest in the institutional knowledge and systems to report emissions, the cost of monitoring should fall and the accuracy of the accounting should improve. A standardized reporting program will also allow for facilities to benchmark themselves against similar facilities to understand better their relative standing within their industry.

2. Summary of Comments and Responses

Comment: Comments received on the benefits of the mandatory reporting program focused on the potential future uses of the collected data. Additional comments on the benefits of the program were concerned that the benefits of the rule are not quantified.

Response: The data collected under this rule will provide comprehensive and accurate data to inform future climate change policies. Potential future CAA and other climate policies include research and development initiatives, economic incentives, new or expanded voluntary programs, adaptation strategies, emission standards, a carbon tax, or a cap-and-trade program. Because EPA does not know at this time the specific policies that may be adopted, the data reported through this rule should be of sufficient quality to support a range of approaches.

Section VI of the RIA for the final rule summarizes the anticipated benefits of the rule, which include providing the government with sound data on which to base future policies and providing industry and the public independently verified information documenting firms' environmental performance. While EPA has not quantified the benefits of the mandatory reporting rule, EPA believes that they are substantial and outweigh the estimated costs.

VIII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under section 3(f)(1) of EO 12866 (58 FR 51735, October 4, 1993), this action is an ''economically significant regulatory action'' because it is likely to have an annual effect on the economy of $100 million or more. Accordingly, EPA submitted this action to the OMB for review under EO 12866 and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, EPA prepared an analysis of the potential costs and benefits associated with this action. A copy of the analysis is available in Docket No. EPA–HQ–OAR–2008–0508, the RIA for the final rule, and is briefly summarized in Section VII of this preamble.

B. Paperwork Reduction Act

The information collection requirements in this 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 requirements are not enforceable until OMB approves them. The ICR document prepared by EPA has been assigned EPA ICR number 2300.03.

EPA plans to collect complete and accurate economy-wide data on facility-level GHG emissions. Accurate and timely information on GHG emissions is essential for informing future climate change policy decisions. Through data collected under this rule, EPA will gain a better understanding of the relative emissions of specific industries, and the distribution of emissions from individual facilities within those industries. The facility-specific data will also improve our understanding of the factors that influence GHG emission rates and actions that facilities are already taking to reduce emissions. Additionally, EPA will be able to track the trend of emissions from industries and facilities within industries over time, particularly in response to policies and potential regulations. The data collected by this rule will improve EPA's ability to formulate climate change policy options and to assess which industries would be affected, and how these industries would be affected by the options.

This information collection is mandatory and will be carried out under CAA sections 114 and 208. Information identified and marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. However, emissions data collected under CAA sections 114 and 208 cannot generally be claimed as CBI and will be made public.[34]

The projected cost and hour burden for non-Federal respondents is $86.3 million and 1.21 million hours per year. The estimated average burden per response is two hours; the frequency of response is annual for all respondents that must comply with the rule's reporting requirements, except for electricity generating units that are already required to report quarterly under 40 CFR part 75 (EPA Acid Rain Program); and the estimated average number of likely respondents per year is 16,725 [35]. The cost burden to respondents resulting from the collection of information includes the total capital cost annualized over the equipment's expected useful life (averaging $9.1 million), a total operation and maintenance component (averaging $11.0 million per year), and a labor cost component (averaging $66.1 million per year). Burden is defined at 5 CFR 1320.3(b). These cost numbers differ from those shown elsewhere in the RIA for the final rule because the ICR costs represent the average cost over the first three years of the rule, but costs are reported elsewhere in the RIA for the final rule for the first year of the rule and for subsequent years of the rule. In addition, the ICR focuses on respondent burden, while the RIA for the final rule includes EPA Agency costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

C. Regulatory Flexibility Act (RFA)

The 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 today's rule on small entities, small entity is defined as: (1) A small business

[34] Although CBI determinations are usually made on a case-by-case basis, EPA has issued guidance in an earlier **Federal Register** notice on what constitutes emissions data that cannot be considered CBI (956 FR 7042–7043, February 21, 1991). As discussed in Section II.R of this preamble, EPA will be initiating a separate notice and comment process to make CBI determinations for the data collected under this rulemaking.

[35] EPA estimates that 30,000 facilities are potentially affected by the rule. Of these, EPA estimates that 10,152 facilities across various sectors will be over their sector-specific reporting threshold and thus required to report; the remaining 19,848 will determine during the first year that they are beneath the threshold and do not need to report. The average number of respondents is thus (30,000+10,152+10,152)/3 = 16,768; excluding 43 Federal facilities, the number of private respondents is 16,725.

as defined by the Small Business Administration's regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of today's final rule on small entities, I therefore certify that this final rule will not have a significant economic impact on a substantial number of small entities.

The small entities directly regulated by this final rule include small businesses across all sectors encompassed by the rule, small governmental jurisdictions and small non-profits. We have determined that some small businesses will be affected because their production processes emit GHGs that must be reported, because they have stationary combustion units on site that emit GHGs that must be reported, or because they have fuel supplier operations for which supply quantities and GHG data must be reported. Small governments and small non-profits are generally affected because they have regulated landfills or stationary combustion units on site, or because they own an LDC.

For affected small entities, EPA conducted a screening assessment comparing compliance costs for affected industry sectors to industry-specific data on revenues for small businesses. This ratio constitutes a ''sales'' test that computes the annualized compliance costs of this final rule as a percentage of sales and determines whether the ratio exceeds some level (e.g., one percent or three percent). The cost-to-sales ratios were constructed at the establishment level (average compliance cost for the establishment/average establishment revenues). As shown in Table VII–5 of this preamble, the cost-to-sales ratios are less than one percent for establishments owned by small businesses that EPA considers most likely to be covered by the reporting program, those with more than 20 employees.[36] For the few sectors where the preliminary screening showed a cost-to-sales ratio exceeding one percent, EPA's examination of firm-specific sales information showed that no affected entity was likely to incur costs exceeding one percent of sales.

The screening analysis thus indicates that the final rule will not have a significant economic impact on a substantial number of small entities. *See* Table VII–5 of this preamble for sector-specific results. The screening assessment for small governments compared the sum of average costs of compliance for combustion, local distribution companies, and landfills to average revenues for small governments. Even for a small government owning all three source types, the costs constitute less than one percent of average revenues for the smallest category of governments (those with fewer than 10,000 people).

Although this final rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless took several steps to reduce the impact of this rule on small entities. For example, EPA determined appropriate thresholds that reduce the number of small businesses reporting. In addition, EPA is not requiring facilities to install CEMS if they do not already have them. Facilities without CEMS can calculate emissions using readily available data or data that are less expensive to collect such as process data or material consumption data. For some source categories, EPA developed tiered methods that are simpler and less burdensome. Also, EPA is requiring annual instead of more frequent reporting.

Through comprehensive outreach activities prior to proposal of the rule, EPA held approximately 100 meetings and/or conference calls with representatives of the primary audience groups, including numerous trade associations and industries that include small business members. EPA's outreach activities prior to proposal of the rule are documented in the memorandum, ''Summary of EPA Outreach Activities for Developing the Greenhouse Gas Reporting Rule,'' located in Docket No. EPA–HQ–OAR–2008–0508–055. After proposal, EPA posted a guide for small businesses on EPA's GHG reporting rule Web site, along with a general fact sheet for the rule, information sheets for every source category, and an FAQ document. EPA also operated a hotline to answer questions about the proposed rule. We continued to meet with stakeholders and entered documentation of all meetings into the docket. We considered public comments, including comments from small businesses and organizations that include small business members, in developing the final rule.

During rule implementation, EPA will maintain an ''open door'' policy for stakeholders to ask questions about the rule or provide suggestions to EPA about the types of compliance assistance that would be useful to small businesses. EPA intends to develop a range of compliance assistance tools and materials and conduct extensive outreach for the final rule.

D. Unfunded Mandates Reform Act (UMRA)

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538, requires Federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector.

EPA has developed this regulation under authority of CAA sections 114 and 208. The required activities under this Federal mandate include monitoring, recordkeeping, and reporting of GHG emissions from multiple source categories (e.g., combustion, process, and biologic). This rule contains a Federal mandate that may result in expenditures of $100 million for the private sector in any one year. As described below, we have determined that the expenditures for State, local, and Tribal governments, in the aggregate, will be approximately $12.1 million per year, based on average costs over the first three years of the rule, including approximately $2 million during the first year of the rule for governments to make a reporting determination and subsequently determine that their emissions are below the threshold and thus, they are not required to report their emissions. Accordingly, EPA has prepared under section 202 of the UMRA a written statement which is summarized below.

Consistent with the intergovernmental consultation provisions of section 204 of the UMRA, EPA initiated an outreach effort with the governmental entities affected by this rule including State, local, and Tribal officials. EPA maintained an ''open door'' policy for stakeholders to provide input on key issues and to help inform EPA's understanding of issues, including impacts to State, local and Tribal governments. The outreach audience included State environmental protection agencies, regional and Tribal organizations, and other State and local government organizations. EPA contacted several States and State and regional organizations already involved in GHG emissions reporting. EPA also conducted several conference calls with Tribal organizations during the proposal phase. For example, EPA staff provided information to tribes through conference calls with multiple Tribal working groups and organizations at EPA and

[36] U.S. Small Business Administration (SBA). 2008. Firm Size Data from the Statistics of U.S. Businesses: U.S. Detail Employment Sizes: 2002. *http://www.census.gov/csd/susb/download_susb02.htm.*

through individual calls with two Tribal board members of TRI. In addition, EPA held meetings and conference calls with groups such as TRI, National Association of Clean Air Agencies (NACAA), ECOS, and with State members of RGGI, the Midwestern GHG Reduction Accord, and WCI. *See* the ''Summary of EPA Outreach Activities for Developing the Greenhouse Gas Reporting Rule,'' in Docket No. EPA–HQ–OAR–2008–0508–055 for a complete list of organizations and groups that EPA contacted.

At proposal of the rule, EPA posted a guide for State and local agencies on the Web site, along with other information sheets, to communicate key aspects of the proposed rule to these agencies. Several State and local agencies and three Tribal organizations or communities submitted written public comments, and EPA carefully considered these comments in developing the final rule. EPA also continued to meet with government agencies or organizations with State members such as California ARB, Connecticut DEP, New Jersey DEP, New Mexico ED, Washington DE, Massachusetts DEP, Illinois EPA, Iowa DNR, and TCR These meetings are documented in the docket. EPA intends to continue to work closely with State, local, and Tribal agencies during rule implementation.

Consistent with section 205 of the UMRA, EPA has identified and considered a reasonable number of regulatory alternatives. EPA carefully examined regulatory alternatives, and selected the lowest cost/least burdensome alternative that EPA deems adequate to address Congressional concerns and to provide a consistent, comprehensive source of information about emissions of GHGs. EPA has considered the costs and benefits of the GHG reporting rule, and has concluded that the costs will fall mainly on the private sector (approximately $77 million), with some costs incurred by State, local, and Tribal governments that must report their emissions (less than $10.1 million) that own and operate stationary combustion units, landfills, or natural gas local distribution companies (LDCs). EPA estimates that an additional 2,034 facilities owned by State, local, or Tribal governments will incur approximately $2.0 million in costs during the first year of the rule to make a reporting determination and subsequently determine that their emissions are below the threshold and thus, they are not required to report their emissions. Furthermore, we think it is unlikely that State, local, and Tribal governments would begin operating large industrial facilities, similar to those affected by this rulemaking operated by the private sector.

Initially, EPA estimates that costs of complying with the final rule will be widely dispersed throughout many sectors of the economy. Although EPA acknowledges that over time changes in the patterns of economic activity may mean that GHG generation and thus reporting costs will change, data are inadequate for projecting these changes. Thus, EPA assumes that costs averaged over the first three years of the program are typical of ongoing costs of compliance. EPA estimates that future compliance costs will total approximately $104 million per year. EPA examined the distribution of these costs between private owners and State, local, and Tribal governments owning GHG emitters. In addition, EPA examined, within the private sector, the impacts on various industries. In general, estimated cost per entity represents less than 0.1 percent of company sales in affected industries. These costs are broadly distributed to a variety of economic sectors and represent approximately 0.001 percent of 2008 Gross Domestic Product; overall, EPA does not believe the final rule will have a significant macroeconomic impact on the national economy. Therefore, this rule is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

EPA does not anticipate that substantial numbers of either public or private sector entities will incur significant economic impacts as a result of this final rule. EPA further expects that benefits of the final rule will include more and better information for EPA and the private sector about emissions of GHGs. This improved information will enhance EPA's ability to develop sound future climate policies, and may encourage GHG emitters to develop voluntary plans to reduce their emissions.

This regulation applies directly to facilities that supply fuel or chemicals that when used emit greenhouse gases, to motor vehicle manufacturers, and to facilities that directly emit greenhouses gases. It does not apply to governmental entities unless the government entity owns a facility that directly emits GHGs above threshold levels such as a landfill or large stationary combustion source, or LDC. In addition, this rule does not impose any implementation responsibilities on State, local, or Tribal governments and it is not expected to increase the cost of existing regulatory programs managed by those governments. Thus, the impact on governments affected by the rule is expected to be minimal.

E. Executive Order 13132: Federalism

EO 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have Federalism implications.'' ''Policies that have Federalism implications'' is defined in the EO to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This final rule does not have Federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in EO 13132. However, for a more detailed discussion about how this final rule relates to existing State programs, *please see* Section II of the proposal preamble (74 FR 16457 to 16461, April 10, 2009) and Sections I.E. and II.C.2 of this preamble.

This regulation applies directly to facilities that supply fuel or chemicals that when used emit greenhouse gases, motor vehicle manufacturers, or facilities that directly emit greenhouses gases. It does not apply to governmental entities unless the government entity owns a facility that directly emits GHGs above threshold levels such as a landfill, large stationary combustion source, or LDC, so relatively few government facilities would be affected. This regulation also does not limit the power of States or localities to collect GHG data and/or regulate GHG emissions. Thus, EO 13132 does not apply to this rule.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicited comments on the proposed rule from State and local officials. *See* Section VIII.D above, for discussion of outreach activities to State, local, or Tribal organizations.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This final rule does not have Tribal implications, as specified in EO 13175 (65 FR 67249, November 9, 2000). This regulation applies directly to facilities that supply fuel or chemicals that when used emit GHGs or facilities that directly emit greenhouses gases. Facilities expected to be affected by the final rule are not expected to be owned by Tribal governments. Thus, Executive Order 13175 does not apply to this final rule.

Although EO 13175 does not apply to this final rule, EPA sought opportunities to provide information to Tribal governments and representatives during development of the rule. In consultation with EPA's American Indian Environment Office, EPA's outreach plan included tribes. EPA conducted several conference calls with Tribal organizations during the proposal phase. For example, EPA staff provided information to tribes through conference calls with multiple Indian working groups and organizations at EPA that interact with tribes and through individual calls with two Tribal board members of TCR. In addition, EPA prepared a short article on the GHG reporting rule that appeared on the front page a Tribal newsletter—Tribal Air News—that was distributed to EPA/OAQPS's network of Tribal organizations. EPA gave a presentation on various climate efforts, including the mandatory reporting rule, at the National Tribal Conference on Environmental Management on June 24–26, 2008. In addition, EPA had copies of a short information sheet distributed at a meeting of the National Tribal Caucus. See the ''Summary of EPA Outreach Activities for Developing the GHG reporting rule,'' in Docket No. EPA–HQ–OAR–2008–0508–055 for a complete list of Tribal contacts. EPA participated in a conference call with Tribal air coordinators in April 2009 and prepared a guidance sheet for Tribal governments on the proposed rule. It was posted on the MRR Web site and published in the Tribal Air Newsletter.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

EPA interprets EO 13045 (62 FR 19885, April 23, 1997) as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the EO has the potential to influence the regulation. This action is not subject to EO 13045 because it does not establish an environmental standard intended to mitigate health or safety risks.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This final rule 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. Further, we have concluded that this rule is not likely to have any adverse energy effects. This final rule relates to monitoring, reporting and recordkeeping at facilities that supply fuel or chemicals that when used emit GHGs or facilities that directly emit greenhouses gases and does not impact energy supply, distribution or use. Therefore, we conclude that this rule is not likely to have any adverse effects on energy supply, distribution, or use.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113 (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory 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, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking involves technical standards. EPA will use more than 60 voluntary consensus standards from 10 different voluntary consensus standards bodies, including the following: ASTM, ASME, ISO, Gas Processors Association, American Gas Association, and National Lime Association. These voluntary consensus standards will help facilities monitor, report, and keep records of GHG emissions. No new test methods were developed for this rule. Instead, from existing rules for source categories and voluntary GHG programs, EPA identified existing means of monitoring, reporting, and keeping records of GHG emissions. The existing methods (voluntary consensus standards) include a broad range of measurement techniques, including many for combustion sources such as methods to analyze fuel and measure its heating value; methods to measure gas or liquid flow; and methods to gauge and measure petroleum and petroleum products. The test methods are incorporated by reference into the final rule and are available as specified in 40 CFR 98.7.

By incorporating voluntary consensus standards into this final rule, EPA is both meeting the requirements of the NTTAA and presenting multiple options and flexibility for measuring GHG emissions.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

EO 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.

EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. This final rule does not affect the level of protection provided to human health or the environment because it is a rule addressing information collection and reporting procedures.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the U.S. prior to publication of the rule in the Federal Register. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective December 29, 2009.

List of Subjects

40 CFR Part 86

Environmental protection, Administrative practice and procedure, Air pollution control, Reporting and recordkeeping requirements, Motor vehicle pollution.

40 CFR Part 87

Environmental protection, Air pollution control, Aircraft, Incorporation by reference.

40 CFR Part 89

Environmental protection, Administrative practice and procedure, Confidential business information, Imports, Labeling, Motor vehicle pollution, Reporting and recordkeeping requirements, Research, Vessels, Warranty.

40 CFR Part 90

Environmental protection, Administrative practice and procedure, Confidential business information, Imports, Labeling, Reporting and recordkeeping requirements, Research, Warranty.

40 CFR Part 94

Environmental protection, Administrative practice and procedure, Air pollution control, Confidential business information, Imports, Incorporation by reference, Labeling, Penalties, Vessels, Reporting and recordkeeping requirements, Warranties.

40 CFR Part 98

Environmental protection, Administrative practice and procedure, Greenhouse gases, Incorporation by reference, Suppliers, Reporting and recordkeeping requirements.

40 CFR Part 1033

Environmental protection, Administrative practice and procedure, Confidential business information, Incorporation by reference, Labeling, Penalties, Railroads, Reporting and recordkeeping requirements.

40 CFR Part 1039

Environmental protection, Administrative practice and procedure, Air pollution control, Confidential business information, Imports, Incorporation by reference, Labeling, Penalties, Reporting and recordkeeping requirements, Warranties.

40 CFR Part 1042

Environmental protection, Administrative practice and procedure, Air pollution control, Confidential business information, Imports, Incorporation by reference, Labeling, Penalties, Vessels, Reporting and recordkeeping requirements, Warranties.

40 CFR Parts 1045, 1048, 1051, and 1054

Environmental protection, Administrative practice and procedure, Air pollution control, Confidential business information, Imports, Incorporation by reference, Labeling, Penalties, Reporting and recordkeeping requirements, Warranties.

40 CFR Part 1065

Environmental protection, Administrative practice and procedure, Incorporation by reference, Reporting and recordkeeping requirements, Research.

Dated: September 22, 2009.

Lisa P. Jackson,

Administrator.

■ For the reasons stated in the preamble, title 40, chapter I, of the Code of Federal Regulations is amended as follows:

PART 86—[AMENDED]

■ 1. The authority citation for part 86 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart A—[Amended]

■ 2. Section 86.007–23 is amended by adding paragraph (n) to read as follows:

§ 86.007–23 Required data.

* * * * *

(n) Measure CO_2, N_2O, and CH_4 with each low-hour certification test for heavy-duty engines using the procedures specified in 40 CFR part 1065 as specified in this paragraph (n). Report these values in your application for certification. The requirements of this paragraph (n) apply starting with model year 2011 for CO_2 and 2012 for CH_4. The requirements of this paragraph (n) related to N_2O emissions apply for engine families that depend on NO_x aftertreatment to meet emission standards starting with model year 2013. These measurements are not required for NTE testing. Use the same units and calculations as for your other results to report a single weighted value for CO_2, N_2O, and CH_4 for each test. Round the final values as follows:

(1) Round CO_2 to the nearest 1 g/bhp-hr.

(2) Round N_2O to the nearest 0.001 g/bhp-hr.

(3) Round CH_4 to the nearest 0.001 g/bhp-hr.

■ 3. Section 86.078–3 is amended by removing the paragraph designation ''(a)'' and adding the abbreviations CH_4 and N_2O in alphanumeric order to read as follows:

§ 86.078–3 Abbreviations.

* * * * *

* * * * *

CH_4 methane.

* * * * *

N_2O nitrous oxide.

* * * * *

Subpart E—[Amended]

■ 4. Section 86.403–78 is amended by adding the abbreviations CH_4 and N_2O in alphanumeric order to read as follows:

§ 86.403–78 Abbreviations.

* * * * *

* * * * *

CH_4 methane.

* * * * *

N_2O nitrous oxide.

* * * * *

■ 5. Section 86.431–78 is amended by adding paragraph (e) to read as follows:

§ 86.431–78 Data submission.

* * * * *

(e) Measure CO_2, N_2O, and CH_4 as described in this paragraph (e) with each zero kilometer certification test (if one is conducted) and with each test conducted at the applicable minimum test distance as defined in § 86.427–78. Use the analytical equipment and procedures specified in 40 CFR part 1065 as needed to measure N_2O and CH_4. Report these values in your application for certification. The requirements of this paragraph (e) apply starting with model year 2011 for CO_2 and 2012 for CH_4. The requirements of this paragraph (e) related to N_2O emissions apply for engine families that depend on NO_X aftertreatment to meet emission standards starting with model year 2013. Small-volume manufacturers (as defined in § 86.410–2006(e)) may omit measurement of N_2O and CH_4; other manufacturers may provide appropriate data and/or information and omit measurement of N_2O and CH_4 as described in 40 CFR 1065.5. Use the same measurement methods as for your other results to report a single value for CO_2, N_2O, and CH_4. Round the final values as follows:

(1) Round CO_2 to the nearest 1 g/km.

(2) Round N_2O to the nearest 0.001 g/km.

(3) Round CH_4 to the nearest 0.001 g/km.

PART 87—[AMENDED]

■ 6. The authority citation for part 87 is revised to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart A—[Amended]

■ 7. Section 87.2 is amended by revising the section heading and adding the abbreviation CO_2 in alphanumeric order to read as follows:

§ 87.2 Acronyms and abbreviations.

* * * * *

CO_2 Carbon dioxide.

* * * * *

■ 8. Section 87.64 is revised to read as follows:

§ 87.64 Sampling and analytical procedures for measuring gaseous exhaust emissions.

(a) The system and procedures for sampling and measurement of gaseous emissions shall be as specified by Appendices 3 and 5 to ICAO Annex 16 (incorporated by reference in § 87.8).

(b) Starting January 1, 2011, report CO_2 values along with your emission levels of regulated NO_X to the Administrator for engines of a type or model of which the date of manufacture of the first individual production model was on or after January 1, 2011. By January 1, 2011, report CO_2 values along with your emission levels of regulated NO_X to the Administrator for engines currently in production and of a type or model for which the date of manufacture of the individual engine was before January 1, 2011. Round CO_2 to the nearest 1 g/kilonewton rO.

(c) Report CO_2 by calculation from fuel mass flow rate measurements in Appendices 3 and 5 to ICAO Annex 16, volume II or alternatively, according to the measurement criteria of CO_2 in Appendices 3 and 5 to ICAO Annex 16, volume II.

PART 89—[AMENDED]

■ 9. The authority citation for part 89 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart B—[Amended]

■ 10. Section 89.115 is amended by revising paragraph (d)(9) to read as follows:

§ 89.115 Application for certificate.

* * * * *

(d) * * *

(9) All test data obtained by the manufacturer on each test engine, including CO_2 as specified in § 89.407(d)(1);

* * * * *

Subpart E—[Amended]

■ 11. Section 89.407 is amended by revising paragraph (d)(1) to read as follows:

§ 89.407 Engine dynamometer test run.

* * * * *

(d) * * *

(1) Measure HC, CO, CO_2, and NO_x concentrations in the exhaust sample. Use the same units and modal calculations as for your other results to report a single weighted value for CO_2; round CO_2 to the nearest 1 g/kW-hr.

* * * * *

PART 90—[AMENDED]

■ 12. The authority citation for part 90 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart B—[Amended]

■ 13. Section 90.107 is amended by revising paragraph (d)(8) to read as follows:

§ 90.107 Application for certification.

* * * * *

(d) * * *

(8) All test data obtained by the manufacturer on each test engine, including CO_2 as specified in § 90.409(c)(1);

* * * * *

Subpart E—[Amended]

■ 14. Section 90.409 is amended by revising paragraph (c)(1) to read as follows:

§ 90.409 Engine dynamometer test run.

* * * * *

(c) * * *

(1) Measure HC, CO, CO_2, and NO_X concentrations in the exhaust sample. Use the same units and modal calculations as for your other results to report a single weighted value for CO_2; round CO_2 to the nearest 1 g/kW–hr.

* * * * *

PART 94—[AMENDED]

■ 15. The authority citation for part 94 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart A—[Amended]

■ 16. Section 94.3 is amended by adding the abbreviation CH_4 in alphanumeric order to read as follows:

§ 94.3 Abbreviations.

* * * * *

CH_4 methane.

* * * * *

Subpart B—[Amended]

■ 17. Section 94.103 is amended by adding paragraph (c) to read as follows:

§ 94.103 Test procedures for Category 1 marine engines.

* * * * *

(c) Measure CH_4 as specified in 40 CFR 1042.235 starting in the 2012 model year.

■ 18. Section 94.104 is amended by adding paragraph (e) to read as follows:

§ 94.104 Test procedures for Category 2 marine engines.

* * * * *

(e) Measure CO_2 as described in 40 CFR 92.129 through the 2010 model year. Measure CO_2 as specified in 40 CFR 1042.235 starting in the 2011 model year. Measure CH_4 as specified in 40 CFR 1042.235 starting in the 2012 model year.

Subpart C—[Amended]

■ 19. Section 94.203 is amended by revising paragraph (d)(10) to read as follows:

§ 94.203 Application for certification.

* * * * *

(d) * * *

(10) All test data obtained by the manufacturer on each test engine, including CO_2 and CH_4 as specified in 40 CFR 89.407(d)(1) and § 94.103(c) for Category 1 engines, § 94.104(e) for Category 2 engines, and § 94.109(d) for Category 3 engines. Small-volume manufacturers may omit measurement and reporting of CH_4.

* * * * *

■ 20. Add part 98 to read as follows:

PART 98—MANDATORY GREENHOUSE GAS REPORTING

Sec.

Subpart A—General Provisions

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

Subpart A—General Provisions

§ 98.1 Purpose and scope.

(a) This part establishes mandatory greenhouse gas (GHG) reporting requirements for owners and operators of certain facilities that directly emit GHG as well as for certain fossil fuel suppliers and industrial GHG suppliers. For suppliers, the GHGs reported are the quantity that would be emitted from combustion or use of the products supplied.

(b) Owners and operators of facilities and suppliers that are subject to this part must follow the requirements of subpart A and all applicable subparts of this part. If a conflict exists between a provision in subpart A and any other applicable subpart, the requirements of the subparts B through PP of this part shall take precedence.

§ 98.2 Who must report?

(a) The GHG reporting requirements and related monitoring, recordkeeping, and reporting requirements of this part apply to the owners and operators of any facility that is located in the United States and that meets the requirements of either paragraph (a)(1), (a)(2), or (a)(3) of this section; and any supplier that meets the requirements of paragraph (a)(4) of this section:

(1) A facility that contains any source category (as defined in subparts C through JJ of this part) that is listed in this paragraph (a)(1) in any calendar year starting in 2010. For these facilities, the annual GHG report must cover all source categories and GHGs for which calculation methodologies are provided in subparts C through JJ of this part.

(i) Electricity generation (units that report CO_2 emissions year-round through 40 CFR part 75).

(ii) Adipic acid production.

(iii) Aluminum production.

(iv) Ammonia manufacturing.

(v) Cement production.

(vi) HCFC–22 production.

(vii) HFC–23 destruction processes that are not collocated with a HCFC–22 production facility and that destroy more than 2.14 metric tons of HFC–23 per year.

(viii) Lime manufacturing.

(ix) Nitric acid production.

(x) Petrochemical production.

(xi) Petroleum refineries.

(xii) Phosphoric acid production.

(xiii) Silicon carbide production.

(xiv) Soda ash production.

(xv) Titanium dioxide production.

(xvi) Municipal solid waste landfills that generate CH_4 in amounts equivalent to 25,000 metric tons CO_2e or more per year, as determined according to subpart HH of this part.

(xvii) Manure management systems with combined CH_4 and N_2O emissions in amounts equivalent to 25,000 metric tons CO_2e or more per year, as determined according to subpart JJ of this part.

(2) A facility that contains any source category (as defined in subparts C through JJ of this part) that is listed in this paragraph (a)(2) in any calendar year starting in 2010 and that emits 25,000 metric tons CO_2e or more per year in combined emissions from stationary fuel combustion units, miscellaneous uses of carbonate, and all source categories that are listed in this paragraph. For these facilities, the annual GHG report must cover all source categories and GHGs for which calculation methodologies are provided in subparts C through JJ of this part.

(i) Ferroalloy Production.

(ii) Glass Production.

(iii) Hydrogen Production.

(iv) Iron and Steel Production.

(v) Lead Production.

(vi) Pulp and Paper Manufacturing.

(vii) Zinc Production.

(3) *A facility that in any calendar year starting in 2010 meets all three of the conditions listed in this paragraph (a)(3).* For these facilities, the annual GHG report must cover emissions from stationary fuel combustion sources only.

(i) The facility does not meet the requirements of either paragraph (a)(1) or (a)(2) of this section.

(ii) The aggregate maximum rated heat input capacity of the stationary fuel combustion units at the facility is 30 mmBtu/hr or greater.

(iii) The facility emits 25,000 metric tons CO_2e or more per year in combined emissions from all stationary fuel combustion sources.

(4) A supplier (as defined in subparts KK through PP of this part) that provides products listed in this paragraph (a)(4) in any calendar year starting in 2010. For these suppliers, the annual GHG report must cover all applicable products for which calculation methodologies are provided in subparts KK through PP of this part.

(i) Coal-to-liquids suppliers, as specified in this paragraph (a)(4)(i).

(A) All producers of coal-to-liquid products.

(B) Importers of an annual quantity of coal-to-liquid products that is equivalent to 25,000 metric tons CO_2e or more.

(C) Exporters of an annual quantity of coal-to-liquid products is equivalent to 25,000 metric tons CO_2e or more.

(ii) Petroleum product suppliers, as specified in this paragraph (a)(4)(ii):

(A) All petroleum refineries that distill crude oil.

(B) Importers of an annual quantity of petroleum products that is equivalent to 25,000 metric tons CO_2e or more.

(C) Exporters of an annual quantity of petroleum products that is equivalent to 25,000 metric tons CO_2e or more.

(iii) Natural gas and natural gas liquids suppliers, as specified in this paragraph (a)(4)(iii):

(A) All natural gas fractionators.

(B) All local natural gas distribution companies.

(iv) Industrial greenhouse gas suppliers, as specified in this paragraph (a)(4)(iv):

(A) All producers of industrial greenhouse gases.

(B) Importers of industrial greenhouse gases with annual bulk imports of N_2O, fluorinated GHG, and CO_2 that in combination are equivalent to 25,000 metric tons CO_2e or more.

(C) Exporters of industrial greenhouse gases with annual bulk exports of N_2O, fluorinated GHG, and CO_2 that in combination are equivalent to 25,000 metric tons CO_2e or more.

(v) Carbon dioxide suppliers, as specified in this paragraph (a)(4)(v).

(A) All producers of CO_2.

(B) Importers of CO_2 with annual bulk imports of N_2O, fluorinated GHG, and CO_2 that in combination are equivalent to 25,000 metric tons CO_2e or more.

(C) Exporters of CO_2 with annual bulk exports of N_2O, fluorinated GHG, and CO_2 that in combination are equivalent to 25,000 metric tons CO_2e or more.

(5) Research and development activities are not considered to be part of any source category defined in this part.

(b) To calculate GHG emissions for comparison to the 25,000 metric ton CO_2e per year emission threshold in paragraph (a)(2) of this section, the owner or operator shall calculate annual

CO_2e emissions, as described in paragraphs (b)(1) through (b)(4) of this section.

(1) Calculate the annual emissions of CO_2, CH_4, N_2O,and each fluorinated GHG in metric tons from all applicable source categories listed in paragraph (a)(2) of this section. The GHG emissions shall be calculated using the calculation methodologies specified in each applicable subpart and available company records. Include emissions from only those gases listed in Table A–1 of this subpart.

(2) For each general stationary fuel combustion unit, calculate the annual CO_2 emissions in metric tons using any of the four calculation methodologies specified in § 98.33(a). Calculate the annual CH_4 and N_2O emissions from the stationary fuel combustion sources in metric tons using the appropriate equation in § 98.33(c). Exclude carbon dioxide emissions from the combustion of biomass, but include emissions of CH_4 and N_2O from biomass combustion.

(3) For miscellaneous uses of carbonate, calculate the annual CO_2 emissions in metric tons using the procedures specified in subpart U of this part.

(4) Sum the emissions estimates from paragraphs (b)(1), (b)(2), and (b)(3) of this section for each GHG and calculate metric tons of CO_2e using Equation A–1 of this section.

$$CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i \qquad \text{(Eq. A-1)}$$

Where:

CO_2e = Carbon dioxide equivalent, metric tons/year.

GHG_i = Mass emissions of each greenhouse gas listed in Table A–1 of this subpart, metric tons/year.

GWP_i = Global warming potential for each greenhouse gas from Table A–1 of this subpart.

n = The number of greenhouse gases emitted.

(5) For purpose of determining if an emission threshold has been exceeded, include in the emissions calculation any CO_2 that is captured for transfer off site.

(c) To calculate GHG emissions for comparison to the 25,000 metric ton CO_2e/year emission threshold for stationary fuel combustion under paragraph (a)(3) of this section, calculate CO_2, CH_4, and N_2O emissions from each stationary fuel combustion unit by following the methods specified in paragraph (b)(2) of this section. Then, convert the emissions of each GHG to metric tons CO_2e per year using Equation A–1 of this section, and sum the emissions for all units at the facility.

(d) To calculate GHG quantities for comparison to the 25,000 metric ton CO_2 per year threshold for importers and exporters of coal-to-liquid products under paragraph (a)(4)(i) of this section, calculate the mass in metric tons per year of CO_2 that would result from the complete combustion or oxidation of the quantity of coal-to-liquid products that are imported during the reporting year and that are exported during the reporting year. Calculate the emissions using the methodology specified in subpart LL of this part.

(e) To calculate GHG quantities for comparison to the 25,000 metric ton CO_2e per year threshold for importers and exporters of petroleum products under paragraph (a)(4)(ii) of this section, calculate the mass in metric tons per year of CO_2 that would result from the complete combustion or oxidation of the volume of petroleum products and natural gas liquids that are imported during the reporting year and that are exported during the reporting year. Calculate the emissions using the methodology specified in subpart MM of this part.

(f) To calculate GHG quantities for comparison to the 25,000 metric ton CO_2e per year threshold under paragraph (a)(4) of this section for importers and exporters of industrial greenhouse gases and for importers and exporters of CO_2, the owner or operator shall calculate the mass in metric tons per year of CO_2e imports and exports as described in paragraphs (f)(1) through (f)(3) of this section.

(1) Calculate the mass in metric tons per year of CO_2, N_2O, and each fluorinated GHG that is imported and the mass in metric tons per year of CO_2, N_2O, and each fluorinated GHG that is exported during the year. Include only those gases listed in Table A–1 of this subpart.

(2) Convert the mass of each imported and each GHG exported from paragraph (f)(1) of this section to metric tons of CO_2e using Equation A–1 of this section.

(3) Sum the total annual metric tons of CO_2e in paragraph (f)(2) of this section for all imported GHGs. Sum the total annual metric tons of CO_2e in paragraph (f)(2) of this section for all exported GHGs.

(g) If a capacity or generation reporting threshold in paragraph (a)(1) of this section applies, the owner or operator shall review the appropriate records and perform any necessary calculations to determine whether the threshold has been exceeded.

(h) An owner or operator of a facility or supplier that does not meet the applicability requirements of paragraph (a) of this section is not subject to this rule. Such owner or operator would become subject to the rule and reporting requirements § 98.3(b)(3), if a facility or supplier exceeds the applicability requirements of paragraph (a) of this section at a later time. Thus, the owner or operator should reevaluate the applicability to this part (including the revising of any relevant emissions calculations or other calculations) whenever there is any change that could cause a facility or supplier to meet the applicability requirements of paragraph (a) of this section. Such changes include but are not limited to process modifications, increases in operating hours, increases in production, changes in fuel or raw material use, addition of equipment, and facility expansion.

(i) Except as provided in this paragraph, once a facility or supplier is subject to the requirements of this part, the owner or operator must continue for each year thereafter to comply with all requirements of this part, including the requirement to submit annual GHG reports, even if the facility or supplier does not meet the applicability requirements in paragraph (a) of this section in a future year.

(1) If reported emissions are less than 25,000 metric tons CO_2e per year for five consecutive years, then the owner or operator may discontinue complying with this part provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and explains the reasons for the reduction in emissions. The notification shall be submitted no later than March 31 of the year immediately following the fifth consecutive year of emissions less than 25,000 tons CO_2e per year. The owner or operator must maintain the corresponding records required under § 98.3(g) for each of the five consecutive years and retain such records for three years following the year that reporting was discontinued. The owner or operator must resume reporting if annual emissions in any future calendar year increase to 25,000 metric tons CO_2e per year or more.

(2) If reported emissions are less than 15,000 metric tons CO_2e per year for three consecutive years, then the owner or operator may discontinue complying with this part provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and explains the reasons for the reduction in emissions. The notification shall be submitted no later than March 31 of the year immediately following the third consecutive year of emissions less than 15,000 tons CO_2e per year. The owner or operator must maintain the corresponding records required under § 98.3(g) for each of the three

consecutive years and retain such records for three years following the year that reporting was discontinued. The owner or operator must resume reporting if annual emissions in any future calendar year increase to 25,000 metric tons CO_2e per year or more.

(3) If the operations of a facility or supplier are changed such that all applicable GHG-emitting processes and operations listed in paragraphs (a)(1) through (a)(4) of this section cease to operate, then the owner or operator is exempt from reporting in the years following the year in which cessation of such operations occurs, provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and certifies to the closure of all GHG-emitting processes and operations. This paragraph (i)(2) does not apply to seasonal or other temporary cessation of operations. This paragraph (i)(2) does not apply to facilities with municipal solid waste landfills. The owner or operator must resume reporting for any future calendar year during which any of the GHG-emitting processes or operations resume operation.

(j) Table A–2 of this subpart provides a conversion table for some of the common units of measure used in part 98.

§ 98.3 What are the general monitoring, reporting, recordkeeping and verification requirements of this part?

The owner or operator of a facility or supplier that is subject to the requirements of this part must submit GHG reports to the Administrator, as specified in this section.

(a) *General*. Except as provided in paragraph (d) of this section, follow the procedures for emission calculation, monitoring, quality assurance, missing data, recordkeeping, and reporting that are specified in each relevant subpart of this part.

(b) *Schedule*. The annual GHG report must be submitted no later than March 31 of each calendar year for GHG emissions in the previous calendar year.

(1) For an existing facility or supplier that began operation before January 1, 2010, report emissions for calendar year 2010 and each subsequent calendar year.

(2) For a new facility or supplier that begins operation on or after January 1, 2010, report emissions beginning with the first operating month and ending on December 31 of that year. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

(3) For any facility or supplier that becomes subject to this rule because of a physical or operational change that is made after January 1, 2010, report emissions for the first calendar year in which the change occurs, beginning with the first month of the change and ending on December 31 of that year. For a facility or supplier that becomes subject to this rule solely because of an increase in hours of operation or level of production, the first month of the change is the month in which the increased hours of operation or level of production, if maintained for the remainder of the year, would cause the facility or supplier to exceed the applicable threshold. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

(c) *Content of the annual report*. Except as provided in paragraph (d) of this section, each annual GHG report shall contain the following information:

(1) Facility name or supplier name (as appropriate) and physical street address including the city, state, and zip code.

(2) Year and months covered by the report.

(3) Date of submittal.

(4) For facilities, report annual emissions of CO_2, CH_4, N_2O, and each fluorinated GHG (as defined in § 98.6) as follows:

(i) Annual emissions (excluding biogenic CO_2) aggregated for all GHG from all applicable source categories in subparts C through JJ of this part and expressed in metric tons of CO_2e calculated using Equation A–1 of this subpart.

(ii) Annual emissions of biogenic CO_2 aggregated for all applicable source categories in subparts C through JJ of this part.

(iii) Annual emissions from each applicable source category in subparts C through JJ of this part, expressed in metric tons of each GHG listed in paragraphs (c)(4)(iii)(A) through (c)(4)(iii)(E) of this section.

(A) Biogenic CO_2.

(B) CO_2 (excluding biogenic CO_2).

(C) CH_4.

(D) N_2O.

(E) Each fluorinated GHG (including those not listed in Table A–1 of this subpart).

(iv) Emissions and other data for individual units. processes, activities, and operations as specified in the ‘‘Data reporting requirements’’ section of each applicable subpart of this part.

(5) For suppliers, report annual quantities of CO_2, CH_4, N_2O, and each fluorinated GHG (as defined in § 98.6) that would be emitted from combustion or use of the products supplied, imported, and exported during the year. Calculate and report quantities at the following levels:

(i) Total quantity of GHG aggregated for all GHG from all applicable supply categories in subparts KK through PP of this part and expressed in metric tons of CO_2e calculated using Equation A–1 of this subpart.

(ii) Quantity of each GHG from each applicable supply category in subparts KK through PP of this part, expressed in metric tons of each GHG. For fluorinated GHG, report emissions of all fluorinated GHG, including those not listed in Table A–1 of this subpart.

(iii) Any other data specified in the ‘‘Data reporting requirements’’ section of each applicable subpart of this part.

(6) A written explanation, as required under § 98.3(e), if you change emission calculation methodologies during the reporting period.

(7) A brief description of each ‘‘best available monitoring method’’ used according to paragraph (d) of this section, the parameter measured using the method, and the time period during which the ‘‘best available monitoring method’’ was used.

(8) Each data element for which a missing data procedure was used according to the procedures of an applicable subpart and the total number of hours in the year that a missing data procedure was used for each data element.

(9) A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of § 98.4(e)(1).

(d) Special provisions for reporting year 2010.

(1) Best available monitoring methods. During January 1, 2010 through March 31, 2010, owners or operators may use best available monitoring methods for any parameter (e.g., fuel use, daily carbon content of feedstock by process line) that cannot reasonably be measured according to the monitoring and QA/QC requirements of a relevant subpart. The owner or operator must use the calculation methodologies and equations in the ‘‘Calculating GHG Emissions’’ sections of each relevant subpart, but may use the best available monitoring method for any parameter for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2010. Starting no later than April 1, 2010, the owner or operator must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part, except as

provided in paragraphs (d)(2) and (d)(3) of this section. Best available monitoring methods means any of the following methods specified in this paragraph:

(i) Monitoring methods currently used by the facility that do not meet the specifications of an relevant subpart.

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(2) *Requests for extension of the use of best available monitoring methods*. The owner or operator may submit a request to the Administrator to use one or more best available monitoring methods beyond March 31, 2010.

(i) *Timing of request*. The extension request must be submitted to EPA no later than 30 days after the effective date of the GHG reporting rule.

(ii) *Content of request*. Requests must contain the following information:

(A) A list of specific item of monitoring instrumentation for which the request is being made and the locations where each piece of monitoring instrumentation will be installed.

(B) Identification of the specific rule requirements (by rule subpart, section, and paragraph numbers) for which the instrumentation is needed.

(C) A description of the reasons why the needed equipment could not be obtained and installed before April 1, 2010.

(D) If the reason for the extension is that the equipment cannot be purchased and delivered by April 1, 2010, include supporting documentation such as the date the monitoring equipment was ordered, investigation of alternative suppliers and the dates by which alternative vendors promised delivery, backorder notices or unexpected delays, descriptions of actions taken to expedite delivery, and the current expected date of delivery.

(E) If the reason for the extension is that the equipment cannot be installed without a process unit shutdown, include supporting documentation demonstrating that it is not practicable to isolate the equipment and install the monitoring instrument without a full process unit shutdown. Include the date of the most recent process unit shutdown, the frequency of shutdowns for this process unit, and the date of the next planned shutdown during which the monitoring equipment can be installed. If there has been a shutdown or if there is a planned process unit shutdown between promulgation of this part and April 1, 2010, include a justification of why the equipment could not be obtained and installed during that shutdown.

(F) A description of the specific actions the facility will take to obtain and install the equipment as soon as reasonably feasible and the expected date by which the equipment will be installed and operating.

(iii) *Approval criteria*. To obtain approval, the owner or operator must demonstrate to the Administrator's satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by April 1, 2010. The use of best available methods will not be approved beyond December 31, 2010.

(3) *Abbreviated emissions report for facilities containing only general stationary fuel combustion sources*. In lieu of the report required by paragraph (c) of this section, the owner or operator of an existing facility that is in operation on January 1, 2010 and that meets the conditions of § 98.2 (a)(3) may submit an abbreviated GHG report for the facility for GHGs emitted in 2010. The abbreviated report must be submitted by March 31, 2011. An owner or operator that submits an abbreviated report must submit a full GHG report according to the requirements of paragraph (c) of this section beginning in calendar year 2011. The abbreviated facility report must include the following information:

(i) Facility name and physical street address including the city, state and zip code.

(ii) The year and months covered by the report.

(iii) Date of submittal.

(iv) Total facility GHG emissions aggregated for all stationary fuel combustion units calculated according to any method specified in § 98.33(a) and expressed in metric tons of CO_2, CH_4, N_2O, and CO_2e.

(v) Any facility operating data or process information used for the GHG emission calculations.

(vi) A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of paragraph (e)(1) of this section.

(e) *Emission calculations*. In preparing the GHG report, you must use the calculation methodologies specified in the relevant subparts, except as specified in paragraph (d) of this section. For each source category, you must use the same calculation methodology throughout a reporting period unless you provide a written explanation of why a change in methodology was required.

(f) *Verification*. To verify the completeness and accuracy of reported GHG emissions, the Administrator may review the certification statements described in paragraphs (c)(8) and (d)(3)(vi) of this section and any other credible evidence, in conjunction with a comprehensive review of the GHG reports and periodic audits of selected reporting facilities. Nothing in this section prohibits the Administrator from using additional information to verify the completeness and accuracy of the reports.

(g) *Recordkeeping*. An owner or operator that is required to report GHGs under this part must keep records as specified in this paragraph. Retain all required records for at least 3 years. The records shall be kept in an electronic or hard-copy format (as appropriate) and recorded in a form that is suitable for expeditious inspection and review. Upon request by the Administrator, the records required under this section must be made available to EPA. Records may be retained off site if the records are readily available for expeditious inspection and review. For records that are electronically generated or maintained, the equipment or software necessary to read the records shall be made available, or, if requested by EPA, electronic records shall be converted to paper documents. You must retain the following records, in addition to those records prescribed in each applicable subpart of this part:

(1) A list of all units, operations, processes, and activities for which GHG emission were calculated.

(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity, categorized by fuel or material type. These data include but are not limited to the following information in this paragraph (g)(2):

(i) The GHG emissions calculations and methods used.

(ii) Analytical results for the development of site-specific emissions factors.

(iii) The results of all required analyses for high heat value, carbon content, and other required fuel or feedstock parameters.

(iv) Any facility operating data or process information used for the GHG emission calculations.

(3) The annual GHG reports.

(4) Missing data computations. For each missing data event, also retain a record of the duration of the event, actions taken to restore malfunctioning monitoring equipment, the cause of the event, and the actions taken to prevent or minimize occurrence in the future.

(5) A written GHG Monitoring Plan.

(i) At a minimum, the GHG Monitoring Plan shall include the elements listed in this paragraph (g)(5)(i).

(A) Identification of positions of responsibility (i.e., job titles) for collection of the emissions data.

(B) Explanation of the processes and methods used to collect the necessary data for the GHG calculations.

(C) Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

(ii) The GHG Monitoring Plan may rely on references to existing corporate documents (e.g., standard operating procedures, quality assurance programs under appendix F to 40 CFR part 60 or appendix B to 40 CFR part 75, and other documents) provided that the elements required by paragraph (g)(5)(i) of this section are easily recognizable.

(iii) The owner or operator shall revise the GHG Monitoring Plan as needed to reflect changes in production processes, monitoring instrumentation, and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime.

(iv) Upon request by the Administrator, the owner or operator shall make all information that is collected in conformance with the GHG Monitoring Plan available for review during an audit. Electronic storage of the information in the plan is permissible, provided that the information can be made available in hard copy upon request during an audit.

(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

(h) *Annual GHG report revisions.* The owner or operator shall submit a revised report within 45 days of discovering or being notified by EPA of errors in an annual GHG report. The revised report must correct all identified errors. The owner or operator shall retain documentation for 3 years to support any revisions made to an annual GHG report.

(i) *Calibration accuracy requirements.* The owner or operator of a facility or supplier that is subject to the requirements of this part must meet the calibration accuracy requirements of this paragraph (i).

(1) Except as provided paragraphs (i)(4) through (i)(6) of this section, flow meters and other devices (e.g., belt scales) that measure data used to calculate GHG emissions shall be calibrated prior to April 1, 2010 using the procedures specified in this paragraph and each relevant subpart of this part. All measurement devices must be calibrated according to the manufacturer's recommended procedures, an appropriate industry consensus standard, or a method specified in a relevant subpart of this part. All measurement devices shall be calibrated to an accuracy of 5 percent. For facilities and suppliers that become subject to this part after April 1, 2010, the initial calibration shall be conducted on the date that data collection is required to begin. Subsequent calibrations shall be performed at the frequency specified in each applicable subpart.

(2) For flow meters, perform all calibrations at measurement points that are representative of normal operation of the meter. Except for the orifice, nozzle, and venturi flow meters described in paragraph (i)(3) of this section, calculate the calibration error at each measurement point using Equation A–2 of this section. The terms "R" and "A" in Equation A–2 must be expressed in consistent units of measure (e.g., gallons/minute, ft^3/min). The calibration error at each measurement point shall not exceed 5.0 percent of the reference value.

$$CE = \frac{R - A}{R} \times 100 \qquad \text{(Eq. A-2)}$$

Where:

CE = Calibration error (%)
R = Reference value
A = Flow meter response to the reference value

(3) For orifice, nozzle, and venturi flow meters, the initial quality assurance consists of in-situ calibration of the differential pressure (delta-P), total pressure, and temperature transmitters. Calibrate each transmitter at a zero point and at least one upscale point. Fixed reference points, such as the freezing point of water, may be used for temperature transmitter calibrations. Calculate the calibration error of each transmitter at each measurement point, using Equation A–3 of this subpart. The terms "R", "A", and "FS" in Equation A–3 of this subpart must be in consistent units of measure (e.g., milliamperes, inches of water, psi, degrees). For each transmitter, the CE value at each measurement point shall not exceed 2.0 percent of full-scale. Alternatively, the results are acceptable if the sum of the calculated CE values for the three transmitters at each calibration level (i.e., at the zero level and at each upscale level) does not exceed 5.0 percent.

$$CE = \frac{R - A}{FS} \times 100 \qquad \text{(Eq. A-3)}$$

Where:

CE = Calibration error (%)
R = Reference value
A = Transmitter response to the reference value
FS = Full-scale value of the transmitter

(4) Fuel billing meters are exempted from the calibration requirements of this section, provided that the fuel supplier and any unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company.

(5) For a flow meter or other measurement device that has been previously calibrated in accordance with this part, an initial calibration is not required by the date specified in paragraph (i)(1) of this section if, as of the date required for the initial calibration, the previous calibration is still active (i.e., the device is not yet due for recalibration because the time interval between successive calibrations, as required by this part, has not elapsed).

(6) For units and processes that operate continuously with infrequent outages, it may not be possible to meet the April 1, 2010 deadline for the initial calibration of a flow meter or other measurement device without removing the device from service and shipping it to a remote location, thereby disrupting normal process operation. In such cases, the owner or operator may postpone the initial calibration until the next scheduled maintenance outage, and may similarly postpone the subsequent recalibrations. Such postponements shall be documented in the monitoring plan that is required under § 98.3(g)(5).

§ 98.4 Authorization and responsibilities of the designated representative.

(a) *General.* Except as provided under paragraph (f) of this section, each facility, and each supplier, that is subject to this part, shall have one and only one designated representative, who shall be responsible for certifying, signing, and submitting GHG emissions reports and any other submissions for such facility and supplier respectively to the Administrator under this part. If the facility is required under any other part of title 40 of the Code of Federal Regulations to submit to the Administrator any other emission report that is subject to any requirement in 40

CFR part 75, the same individual shall be the designated representative responsible for certifying, signing, and submitting the GHG emissions reports and all such other emissions reports under this part.

(b) *Authorization of a designated representative.* The designated representative of the facility or supplier shall be an individual selected by an agreement binding on the owners and operators of such facility or supplier and shall act in accordance with the certification statement in paragraph (i)(4)(iv) of this section.

(c) *Responsibility of the designated representative.* Upon receipt by the Administrator of a complete certificate of representation under this section for a facility or supplier, the designated representative identified in such certificate of representation shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of such facility or supplier in all matters pertaining to this part, notwithstanding any agreement between the designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the designated representative by the Administrator or a court.

(d) *Timing.* No GHG emissions report or other submissions under this part for a facility or supplier will be accepted until the Administrator has received a complete certificate of representation under this section for a designated representative of the facility or supplier. Such certificate of representation shall be submitted at least 60 days before the deadline for submission of the facility's or supplier's initial emission report under this part.

(e) *Certification of the GHG emissions report.* Each GHG emission report and any other submission under this part for a facility or supplier shall be certified, signed, and submitted by the designated representative or any alternate designated representative of the facility or supplier in accordance with this section and § 3.10 of this chapter.

(1) Each such submission shall include the following certification statement signed by the designated representative or any alternate designated representative: ''I am authorized to make this submission on behalf of the owners and operators of the facility or supplier, as applicable, for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) The Administrator will accept a GHG emission report or other submission for a facility or supplier under this part only if the submission is certified, signed, and submitted in accordance with this section.

(f) *Alternate designated representative.* A certificate of representation under this section for a facility or supplier may designate one alternate designated representative, who shall be an individual selected by an agreement binding on the owners and operators, and may act on behalf of the designated representative, of such facility or supplier. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) Upon receipt by the Administrator of a complete certificate of representation under this section for a facility or supplier identifying an alternate designated representative.

(i) The alternate designated representative may act on behalf of the designated representative for such facility or supplier.

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative.

(2) Except in this section, whenever the term ''designated representative'' is used in this part, the term shall be construed to include the designated representative or any alternate designated representative.

(g) *Changing a designated representative or alternate designated representative.* The designated representative or alternate designated representative identified in a complete certificate of representation under this section for a facility or supplier received by the Administrator may be changed at any time upon receipt by the Administrator of another later signed, complete certificate of representation under this section for the facility or supplier. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative or the previous alternate designated representative of the facility or supplier before the time and date when the Administrator receives such later signed certificate of representation shall be binding on the new designated representative and the owners and operators of the facility or supplier.

(h) *Changes in owners and operators.* In the event an owner or operator of the facility or supplier is not included in the list of owners and operators in the certificate of representation under this section for the facility or supplier, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the facility or supplier, as if the owner or operator were included in such list. Within 90 days after any change in the owners and operators of the facility or supplier (including the addition of a new owner or operator), the designated representative or any alternate designated representative shall submit a certificate of representation that is complete under this section except that such list shall be amended to reflect the change. If the designated representative or alternate designated representative determines at any time that an owner or operator of the facility or supplier is not included in such list and such exclusion is not the result of a change in the owners and operators, the designated representative or any alternate designated representative shall submit, within 90 days of making such determination, a certificate of representation that is complete under this section except that such list shall be amended to include such owner or operator.

(i) *Certificate of representation.* A certificate of representation shall be complete if it includes the following elements in a format prescribed by the Administrator in accordance with this section:

(1) Identification of the facility or supplier for which the certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the facility or supplier identified in paragraph (i)(1) of this section, provided that, if the list includes the operators of the facility or supplier and the owners with control of the facility or supplier, the failure to include any other owners shall not make the certificate of representation incomplete.

(4) The following certification statements by the designated representative and any alternate designated representative:

(i) ''I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the facility or supplier, as applicable.''

(ii) ''I certify that I have all the necessary authority to carry out my duties and responsibilities under 40 CFR part 98 on behalf of the owners and operators of the facility or supplier, as applicable, and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.''

(iii) ''I certify that the owners and operators of the facility or supplier, as applicable, shall be bound by any order issued to me by the Administrator or a court regarding the facility or supplier.''

(iv) ''If there are multiple owners and operators of the facility or supplier, as applicable, I certify that I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the facility or supplier.''

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(j) *Documents of agreement.* Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(k) *Binding nature of the certificate of representation.* Once a complete certificate of representation under this section for a facility or supplier has been received, the Administrator will rely on the certificate of representation unless and until a later signed, complete certificate of representation under this section for the facility or supplier is received by the Administrator.

(l) Objections Concerning a Designated Representative

(1) Except as provided in paragraph (g) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative, or the finality of any decision or order by the Administrator under this part.

(2) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative.

(m) *Delegation by designated representative and alternate designated representative.*

(1) A designated representative or an alternate designated representative may delegate his or her own authority, to one or more individuals, to submit an electronic submission to the Administrator provided for or required under this part, except for a submission under this paragraph.

(2) In order to delegate his or her own authority, to one or more individuals, to submit an electronic submission to the Administrator in accordance with paragraph (m)(1) of this section, the designated representative or alternate designated representative must submit electronically to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(i) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative.

(ii) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such individual (referred to as an ''agent'').

(iii) For each such individual, a list of the type or types of electronic submissions under paragraph (m)(1) of this section for which authority is delegated to him or her.

(iv) For each type of electronic submission listed in accordance with paragraph (m)(2)(iii) of this section, the facility or supplier for which the electronic submission may be made.

(v) The following certification statements by such designated representative or alternate designated representative:

(A) ''I agree that any electronic submission to the Administrator that is by an agent identified in this notice of delegation and of a type listed, and for a facility or supplier designated, for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as applicable, and before this notice of delegation is superseded by another notice of delegation under § 98.4(m)(3) shall be deemed to be an electronic submission certified, signed, and submitted by me.''

(B) ''Until this notice of delegation is superseded by a later signed notice of delegation under § 98.4(m)(3), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under § 98.4(m) is terminated.''

(vi) The signature of such designated representative or alternate designated representative and the date signed.

(3) A notice of delegation submitted in accordance with paragraph (m)(2) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of another such notice that was signed later by such designated representative or alternate designated representative, as applicable. The later signed notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(4) Any electronic submission covered by the certification in paragraph (m)(2)(iv)(A) of this section and made in accordance with a notice of delegation effective under paragraph (m)(3) of this section shall be deemed to be an electronic submission certified, signed, and submitted by the designated representative or alternate designated representative submitting such notice of delegation.

§ 98.5 How is the report submitted?

Each GHG report and certificate of representation for a facility or supplier must be submitted electronically in accordance with the requirements of § 98.4 and in a format specified by the Administrator.

§ 98.6 Definitions.

All terms used in this part shall have the same meaning given in the Clean Air Act and in this section.

Accuracy of a measurement at a specified level (e.g., one percent of full scale or one percent of the value measured) means that the mean of repeat measurements made by a device or technique are within 95 percent of the range bounded by the true value plus or minus the specified level.

Acid Rain Program means the program established under title IV of the Clean Air Act, and implemented under parts 72 through 78 of this chapter for the reduction of sulfur dioxide and nitrogen oxides emissions.

Administrator means the Administrator of the United States

Environmental Protection Agency or the Administrator's authorized representative.

AGA means the American Gas Association

Alkali bypass means a duct between the feed end of the kiln and the preheater tower through which a portion of the kiln exit gas stream is withdrawn and quickly cooled by air or water to avoid excessive buildup of alkali, chloride and/or sulfur on the raw feed. This may also be referred to as the ''kiln exhaust gas bypass.''

Anaerobic digester means the system where wastes are collected and anaerobically digested in large containment vessels or covered lagoons. Anaerobic digesters stabilize waste by the microbial reduction of complex organic compounds to CO2 and CH4, which is captured and may be flared or used as fuel. Anaerobic digestion systems, include but are not limited to covered lagoon, complete mix, plug flow, and fixed film digesters.

Anaerobic lagoon means a type of liquid storage system component, either at manure management system or a wastewater treatment system, that is designed and operated to stabilize wastes using anaerobic microbial processes. Anaerobic lagoons may be designed for combined stabilization and storage with varying lengths of retention time (up to a year or greater), depending on the climate region, the volatile solids loading rate, and other operational factors.

Anode effect is a process upset condition of an aluminum electrolysis cell caused by too little alumina dissolved in the electrolyte. The anode effect begins when the voltage rises rapidly and exceeds a threshold voltage, typically 8 volts.

Anode Effect Minutes per Cell Day (24 hours) are the total minutes during which an electrolysis cell voltage is above the threshold voltage, typically 8 volts.

ANSI means the American National Standards Institute.

API means the American Petroleum Institute.

Argon-oxygen decarburization (AOD) vessel means any closed-bottom, refractory-lined converter vessel with submerged tuyeres through which gaseous mixtures containing argon and oxygen or nitrogen may be blown into molten steel for further refining to reduce the carbon content of the steel.

ASABE means the American Society of Agricultural and Biological Engineers.

ASME means the American Society of Mechanical Engineers.

ASTM means the American Society of Testing and Materials.

Asphalt means a dark brown-to-black cement-like material obtained by petroleum processing and containing bitumens as the predominant component. It includes crude asphalt as well as the following finished products: cements, fluxes, the asphalt content of emulsions (exclusive of water), and petroleum distillates blended with asphalt to make cutback asphalts.

Aviation Gasoline means a complex mixture of volatile hydrocarbons, with or without additives, suitably blended to be used in aviation reciprocating engines. Specifications can be found in ASTM Specification D910–07a, Standard Specification for Aviation Gasolines (incorporated by reference, see § 98.7).

B_0 means the maximum CH_4 producing capacity of a waste stream, kg CH_4/kg COD.

Basic oxygen furnace means any refractory-lined vessel in which high-purity oxygen is blown under pressure through a bath of molten iron, scrap metal, and fluxes to produce steel.

bbl means barrel.

Biodiesel means a mono-akyl ester derived from biomass and conforming to ASTM D6751–08, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels.

Biogenic CO_2 means carbon dioxide emissions generated as the result of biomass combustion from combustion units for which emission calculations are required by an applicable part 98 subpart.

Biomass means non-fossilized and biodegradable organic material originating from plants, animals or micro-organisms, including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material.

Blast furnace means a furnace that is located at an integrated iron and steel plant and is used for the production of molten iron from iron ore pellets and other iron bearing materials.

Blendstocks are petroleum products used for blending or compounding into finished motor gasoline. These include RBOB (reformulated blendstock for oxygenate blending) and CBOB (conventional blendstock for oxygenate blending), but exclude oxygenates, butane, and pentanes plus.

Blendstocks—Others are products used for blending or compounding into finished motor gasoline that are not defined elsewhere. Excludes Gasoline Treated as Blendstock (GTAB), Diesel Treated as Blendstock (DTAB), conventional blendstock for oxygenate blending (CBOB), reformulated blendstock for oxygenate blending (RBOB), oxygenates (e.g. fuel ethanol and methyl tertiary butyl ether), butane, and pentanes plus.

Blowdown mean the act of emptying or depressuring a vessel. This may also refer to the discarded material such as blowdown water from a boiler or cooling tower.

British Thermal Unit or Btu means the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit at about 39.2 degrees Fahrenheit.

Bulk, with respect to industrial GHG suppliers and CO2 suppliers, means the transfer of a product inside containers, including but not limited to tanks, cylinders, drums, and pressure vessels.

Bulk natural gas liquid or NGL refers to mixtures of hydrocarbons that have been separated from natural gas as liquids through the process of absorption, condensation, adsorption, or other methods at lease separators and field facilities. Generally, such liquids consist of ethane, propane, butanes, and pentanes plus. Bulk NGL is sold to fractionators or to refineries and petrochemical plants where the fractionation takes place.

Butane, or n-Butane, is a paraffinic straight-chain hydrocarbon with molecular formula C_4H_{10}.

Butylene, or n-Butylene, is an olefinic straight-chain hydrocarbon with molecular formula C_4H_8.

By-product coke oven battery means a group of ovens connected by common walls, where coal undergoes destructive distillation under positive pressure to produce coke and coke oven gas from which by-products are recovered.

Calcination means the process of thermally treating minerals to decompose carbonates from ore.

Calculation methodology means a methodology prescribed under the section ''Calculating GHG Emissions'' in any subpart of part 98.

Carbon dioxide equivalent or CO_2e means the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas, and is calculated using Equation A–1 of this subpart.

Carbon dioxide production well means any hole drilled in the earth for the primary purpose of extracting carbon dioxide from a geologic formation or group of formations which contain deposits of carbon dioxide.

Carbon dioxide production well facility means one or more carbon dioxide production wells that are located on one or more contiguous or adjacent properties, which are under the control of the same entity. Carbon dioxide production wells located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line, or pipeline, shall be considered part of the same CO_2 production well facility if they otherwise meet the definition.

Carbon dioxide stream means carbon dioxide that has been captured from an emission source (e.g. a power plant or other industrial facility) or extracted from a carbon dioxide production well plus incidental associated substances either derived from the source materials and the capture process or extracted with the carbon dioxide.

Carbon share means the percent of total mass that carbon represents in any product.

Carbonate means compounds containing the radical CO_3^{-2}. Upon calcination, the carbonate radical decomposes to evolve carbon dioxide (CO_2). Common carbonates consumed in the mineral industry include calcium carbonate ($CaCO_3$) or calcite; magnesium carbonate ($MgCO_3$) or magnesite; and calcium-magnesium carbonate ($CaMg(CO_3)_2$) or dolomite.

Carbonate-based mineral means any of the following minerals used in the manufacture of glass: Calcium carbonate ($CaCO_3$), calcium magnesium carbonate ($CaMg(CO_3)_2$), and sodium carbonate (Na_2CO_3).

Carbonate-based mineral mass fraction means the following: For limestone, the mass fraction of $CaCO_3$ in the limestone; for dolomite, the mass fraction of $CaMg(CO_3)_2$ in the dolomite; and for soda ash, the mass fraction of Na_2CO_3 in the soda ash.

Carbonate-based raw material means any of the following materials used in the manufacture of glass: Limestone, dolomite, and soda ash.

Catalytic cracking unit means a refinery process unit in which petroleum derivatives are continuously charged and hydrocarbon molecules in the presence of a catalyst are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. Catalytic cracking units include both fluidized bed systems, which are referred to as fluid catalytic cracking units (FCCU), and moving bed systems, which are also referred to as thermal catalytic cracking units. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery.

Deep bedding systems for cattle swine means a manure management system in which, as manure accumulates, bedding is continually added to absorb moisture over a production cycle and possibly for as long as 6 to 12 months. This manure management system also is known as a bedded pack manure management system and may be combined with a dry lot or pasture.

CBOB-Summer (conventional blendstock for oxygenate blending) means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of Conventional-Summer.

CBOB-Winter (conventional blendstock for oxygenate blending) means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of Conventional-Winter.

Certified standards means calibration gases certified by the manufacturer of the calibration gases to be accurate to within 2 percent of the value on the label or calibration gases.

CH_4 means methane.

Chemical recovery combustion unit means a combustion device, such as a recovery furnace or fluidized-bed reactor where spent pulping liquor from sulfite or semi-chemical pulping processes is burned to recover pulping chemicals.

Chemical recovery furnace means an enclosed combustion device where concentrated spent liquor produced by the kraft or soda pulping process is burned to recover pulping chemicals and produce steam. Includes any recovery furnace that burns spent pulping liquor produced from both the kraft and soda pulping processes.

Chloride process means a production process where titanium dioxide is produced using calcined petroleum coke and chlorine as raw materials.

City gate means a location at which natural gas ownership or control passes from one party to another, neither of which is the ultimate consumer. In this rule, in keeping with common practice, the term refers to a point or measuring station at which a local gas distribution utility receives gas from a natural gas pipeline company or transmission system. Meters at the city gate station measure the flow of natural gas into the local distribution company system and typically are used to measure local distribution company system sendout to customers.

CO_2 means carbon dioxide.

Coal means all solid fuels classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388–05 Standard Classification of Coals by Rank (incorporated by reference, *see* § 98.7).

COD means the chemical oxygen demand as determined using methods specified pursuant to 40 CFR part 136.

Coke burn-off means the coke removed from the surface of a catalyst by combustion during catalyst regeneration. Coke burn-off also means the coke combusted in fluid coking unit burner.

Cokemaking means the production of coke from coal in either a by-product coke oven battery or a non-recovery coke oven battery.

Commercial applications means executing a commercial transaction subject to a contract. A commercial application includes transferring custody of a product from one facility to another if it otherwise meets the definition.

Company records means, in reference to the amount of fuel consumed by a stationary combustion unit (or by a group of such units), a complete record of the methods used, the measurements made, and the calculations performed to quantify fuel usage. Company records may include, but are not limited to, direct measurements of fuel consumption by gravimetric or volumetric means, tank drop measurements, and calculated values of fuel usage obtained by measuring auxiliary parameters such as steam generation or unit operating hours. Fuel billing records obtained from the fuel supplier qualify as company records.

Connector means to flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, pipe components (such as elbows, reducers, ''T's'' or valves) or a pipe line and a piece of equipment or an instrument to a pipe, tube or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this part.

Container glass means glass made of soda-lime recipe, clear or colored, which is pressed and/or blown into bottles, jars, ampoules, and other products listed in North American Industry Classification System 327213 (NAICS 327213).

Continuous emission monitoring system or CEMS means the total equipment required to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes, a permanent record of gas concentrations, pollutant emission rates, or gas volumetric flow rates from stationary sources.

Continuous glass melting furnace means a glass melting furnace that operates continuously except during periods of maintenance, malfunction, control device installation, reconstruction, or rebuilding.

Conventional-Summer refers to finished gasoline formulated for use in motor vehicles, the composition and properties of which do not meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR 80.40, but which meet summer RVP standards required under 40 CFR 80.27 or as specified by the state. **Note:** This category excludes conventional gasoline for oxygenate blending (CBOB) as well as other blendstock.

Conventional-Winter refers to finished gasoline formulated for use in motor vehicles, the composition and properties of which do not meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR 80.40 or the summer RVP standards required under 40 CFR 80.27 or as specified by the state. **Note:** This category excludes conventional blendstock for oxygenate blending (CBOB) as well as other blendstock.

Crude oil means a mixture of hydrocarbons that exists in the liquid phase in the underground reservoir and remains liquid at atmospheric pressure after passing through surface separating facilities.

Daily spread means a manure management system component in which manure is routinely removed from a confinement facility and is applied to cropland or pasture within 24 hours of excretion.

Day means any consistently designated 24 hour period during which an emission unit is operated.

Degradable organic carbon (DOC) means the fraction of the total mass of a waste material that can be biologically degraded.

Delayed coking unit means one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors. A *delayed coking unit* consists of the coke drums and ancillary equipment associated with a single fractionator.

Density means the mass contained in a given unit volume (mass/volume).

Destruction means:

(1) With respect to landfills and manure management, the combustion of methane in any on-site or off-site combustion technology. Destroyed methane includes, but is not limited to, methane combusted by flaring, methane destroyed by thermal oxidation, methane combusted for use in on-site energy or heat production technologies, methane that is conveyed through pipelines (including natural gas pipelines) for off-site combustion, and methane that is collected for any other on-site or off-site use as a fuel.

(2) With respect to fluorinated GHGs, the expiration of a fluorinated GHG to the destruction efficiency actually achieved. Such destruction does not result in a commercially useful end product.

Destruction Efficiency means the efficiency with which a destruction device reduces the GWP-weighted mass of greenhouse gases fed into the device, considering the GWP-weighted masses of both the greenhouse gases fed into the device and those exhausted from the device. Destruction efficiency, or flaring destruction efficiency, refers to the fraction of the gas that leaves the flare partially or fully oxidized. The Destruction Efficiency is expressed in Equation A–2 of this section:

$$DE = 1 - \frac{tCO_2e_{OUT}}{tCO_2e_{IN}} \qquad \text{(Eq. A-2)}$$

Where:

DE = Destruction Efficiency

tCO_2e_{IN} = The GWP-weighted mass of GHGs fed into the destruction device

tCO_2e_{OUT} = The GWP-weighted mass of GHGs exhausted from the destruction device, including GHGs formed during the destruction process

Diesel—Other is any distillate fuel oil not defined elsewhere, including Diesel Treated as Blendstock (DTAB).

DIPE (diisopropyl ether, $(CH_3)_2CHOCH(CH_3)_2$) is an ether as described in ‘‘Oxygenates.’’

Direct liquefaction means the conversion of coal directly into liquids, rather than passing through an intermediate gaseous state.

Direct reduction furnace means a high temperature furnace typically fired with natural gas to produce solid iron from iron ore or iron ore pellets and coke, coal, or other carbonaceous materials.

Distillate Fuel Oil means a classification for one of the petroleum fractions produced in conventional distillation operations and from crackers and hydrotreating process units. The generic term distillate fuel oil includes kerosene, diesel fuels (Diesel Fuels No. 1, No. 2, and No. 4), and fuel oils (Fuel Oils No. 1, No. 2, and No. 4).

Distillate Fuel No. 1 has a maximum distillation temperature of 550 °F at the 90 percent recovery point and a minimum flash point of 100 °F and includes fuels commonly known as Diesel Fuel No. 1 and Fuel Oil No. 1, but excludes kerosene. This fuel is further subdivided into categories of sulfur content: High Sulfur (greater than 500 ppm), Low Sulfur (less than or equal to 500 ppm and greater than 15 ppm), and Ultra Low Sulfur (less than or equal to 15 ppm).

Distillate Fuel No. 2 has a minimum and maximum distillation temperature of 540 °F and 640 °F at the 90 percent recovery point, respectively, and includes fuels commonly known as Diesel Fuel No. 2 and Fuel Oil No. 2. This fuel is further subdivided into categories of sulfur content: High Sulfur (greater than 500 ppm), Low Sulfur (less than or equal to 500 ppm and greater than 15 ppm), and Ultra Low Sulfur (less than or equal to 15 ppm).

Distillate Fuel No. 4 is a distillate fuel oil made by blending distillate fuel oil and residual fuel oil, with a minimum flash point of 131 °F.

DOC_f means the fraction of DOC that actually decomposes under the (presumably anaerobic) conditions within the landfill.

Dry lot means a manure management system component consisting of a paved or unpaved open confinement area without any significant vegetative cover where accumulating manure may be removed periodically.

Electric arc furnace (EAF) means a furnace that produces molten alloy metal and heats the charge materials with electric arcs from carbon electrodes.

Electric arc furnace steelmaking means the production of carbon, alloy, or specialty steels using an EAF. This definition excludes EAFs at steel foundries and EAFs used to produce nonferrous metals.

Electrothermic furnace means a furnace that heats the charged materials with electric arcs from carbon electrodes.

Emergency generator means a stationary combustion device, such as a reciprocating internal combustion engine or turbine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the owner or operator of a facility. An emergency generator operates only during emergency situations, for training of personnel under simulated emergency conditions, as part of emergency demand response procedures, or for standard performance testing procedures as required by law or by the generator manufacturer. A generator that serves as a back-up power source under conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power service agreement, or scheduled facility maintenance shall not be considered an emergency generator.

Emergency equipment means any auxiliary fossil fuel-powered equipment, such as a fire pump, that is used only in emergency situations.

ETBE (ethyl tertiary butyl ether, $(CH_3)_3COC_2H$) is an ether as described in ''Oxygenates.''

Ethane is a paraffinic hydrocarbon with molecular formula C_2H_6.

Ethanol is an anhydrous alcohol with molecular formula C_2H_5OH.

Ethylene is an olefinic hydrocarbon with molecular formula C_2H_4.

Ex refinery gate means the point at which a petroleum product leaves the refinery.

Experimental furnace means a glass melting furnace with the sole purpose of operating to evaluate glass melting processes, technologies, or glass products. An experimental furnace does not produce glass that is sold (except for further research and development purposes) or that is used as a raw material for non-experimental furnaces.

Export means to transport a product from inside the United States to persons outside the United States, excluding any such transport on behalf of the United States military including foreign military sales under the Arms Export Control Act.

Exporter means any person, company or organization of record that transfers for sale or for other benefit, domestic products from the United States to another country or to an affiliate in another country, excluding any such transfers on behalf of the United States military or military purposes including foreign military sales under the Arms Export Control Act. An exporter is not the entity merely transporting the domestic products, rather an exporter is the entity deriving the principal benefit from the transaction.

Facility means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

Feed means the prepared and mixed materials, which include but are not limited to materials such as limestone, clay, shale, sand, iron ore, mill scale, cement kiln dust and flyash, that are fed to the kiln. Feed does not include the fuels used in the kiln to produce heat to form the clinker product.

Feedstock means raw material inputs to a process that are transformed by reaction, oxidation, or other chemical or physical methods into products and by-products. Supplemental fuel burned to provide heat or thermal energy is not a feedstock.

Fischer-Tropsch process means a catalyzed chemical reaction in which synthesis gas, a mixture of carbon monoxide and hydrogen, is converted into liquid hydrocarbons of various forms.

Flare means a combustion device, whether at ground level or elevated, that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame.

Flat glass means glass made of soda-lime recipe and produced into continuous flat sheets and other products listed in NAICS 327211.

Flowmeter means a device that measures the mass or volumetric rate of flow of a gas, liquid, or solid moving through an open or closed conduit (e.g. flowmeters include, but are not limited to, rotameters, turbine meters, coriolis meters, orifice meters, ultra-sonic flowmeters, and vortex flowmeters).

Fluid coking unit means one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced in a fluidized bed system. The fluid coking unit includes equipment for controlling air pollutant emissions and for heat recovery on the fluid coking burner exhaust vent. There are two basic types of fluid coking units: A traditional fluid coking unit in which only a small portion of the coke produced in the unit is burned to fuel the unit and the fluid coking burner exhaust vent is directed to the atmosphere (after processing in a CO boiler or other air pollutant control equipment) and a flexicoking unit in which an auxiliary burner is used to partially combust a significant portion of the produced petroleum coke to generate a low value fuel gas that is used as fuel in other combustion sources at the refinery.

Fluorinated greenhouse gas means sulfur hexafluoride (SF_6), nitrogen trifluoride (NF_3), and any fluorocarbon except for controlled substances as defined at 40 CFR part 82, subpart A and substances with vapor pressures of less than 1 mm of Hg absolute at 25 degrees C. With these exceptions, ''fluorinated GHG'' includes but is not limited to any hydrofluorocarbon, any perfluorocarbon, any fully fluorinated linear, branched or cyclic alkane, ether, tertiary amine or aminoether, any perfluoropolyether, and any hydrofluoropolyether.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material, including for example, consumer products that are derived from such materials and are combusted.

Fossil fuel-fired means powered by combustion of fossil fuel, alone or in combination with any other fuel, regardless of the percentage of fossil fuel consumed.

Fractionators means plants that produce fractionated natural gas liquids (NGLs) extracted from produced natural gas and separate the NGLs individual component products: ethane, propane, butanes and pentane-plus (C5+). Plants that only process natural gas but do not fractionate NGLs further into component products are not considered fractionators. Some fractionators do not process production gas, but instead fractionate bulk NGLs received from natural gas processors. Some fractionators both process natural gas and fractionate bulk NGLs received from other plants.

Fuel means solid, liquid or gaseous combustible material.

Fuel gas means gas generated at a petroleum refinery, petrochemical plant, or similar industrial process unit, and that is combusted separately or in any combination with any type of gas.

Fuel gas system means a system of compressors, piping, knock-out pots, mix drums, and, if necessary, units used to remove sulfur contaminants from the fuel gas (e.g., amine scrubbers) that collects fuel gas from one or more sources for treatment, as necessary, and transport to a stationary combustion unit. A fuel gas system may have an overpressure vent to a flare but the primary purpose for a fuel gas system is to provide fuel to the various combustion units at the refinery or petrochemical plant.

Gas collection system or landfill gas collection system means a system of pipes used to collect landfill gas from different locations in the landfill to a single location for treatment (thermal destruction) or use. Landfill gas collection systems may also include knock-out or separator drums and/or a compressor.

Gas-fired unit means a stationary combustion unit that derives more than 50 percent of its annual heat input from the combustion of gaseous fuels, and the remainder of its annual heat input from the combustion of fuel oil or other liquid fuels.

Gas monitor means an instrument that continuously measures the concentration of a particular gaseous species in the effluent of a stationary source.

Gaseous fuel means a material that is in the gaseous state at standard atmospheric temperature and pressure conditions and that is combusted to produce heat and/or energy.

Gasification means the conversion of a solid or liquid raw material into a gas.

Gasoline—Other is any gasoline that is not defined elsewhere, including GTAB (gasoline treated as blendstock).

Glass melting furnace means a unit comprising a refractory-lined vessel in which raw materials are charged and melted at high temperature to produce molten glass.

Glass produced means the weight of glass exiting a glass melting furnace.

Global warming potential or GWP means the ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram of a trace substance relative to that of one kilogram- of a reference gas, i.e., CO_2.

GPA means the Gas Processors Association.

Greenhouse gas or GHG means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and other fluorinated greenhouse gases as defined in this section.

GTBA (gasoline-grade tertiary butyl alcohol, $(CH_3)_3COH$), or t-butanol, is an alcohol as described in ''Oxygenates.''

Heavy Gas Oils are petroleum distillates with an approximate boiling range from 651 °F to 1,000 °F.

Heel means the amount of gas that remains in a shipping container after it is discharged or off-loaded (that is no more than ten percent of the volume of the container).

High heat value or HHV means the high or gross heat content of the fuel with the heat of vaporization included. The water is assumed to be in a liquid state.

Hydrofluorocarbons or HFCs means a class of GHGs consisting of hydrogen, fluorine, and carbon.

Import means, to land on, bring into, or introduce into, any place subject to the jurisdiction of the United States whether or not such landing, bringing, or introduction constitutes an importation within the meaning of the customs laws of the United States, with the following exemptions:

(1) Off-loading used or excess fluorinated GHGs or nitrous oxide of U.S. origin from a ship during servicing.

(2) Bringing fluorinated GHGs or nitrous oxide into the U.S. from Mexico where the fluorinated GHGs or nitrous oxide had been admitted into Mexico in bond and were of U.S. origin.

(3) Bringing fluorinated GHGs or nitrous oxide into the U.S. when transported in a consignment of personal or household effects or in a similar non-commercial situation normally exempted from U.S. Customs attention.

(4) Bringing fluorinated GHGs or nitrous into U.S. jurisdiction exclusively for U. S. military purposes.

Importer means any person, company, or organization of record that for any reason brings a product into the United States from a foreign country, excluding introduction into U.S. jurisdiction exclusively for United States military purposes. An importer is the person, company, or organization primarily liable for the payment of any duties on the merchandise or an authorized agent acting on their behalf. The term includes, as appropriate:

(1) The consignee.

(2) The importer of record.

(3) The actual owner.

(4) The transferee, if the right to draw merchandise in a bonded warehouse has been transferred.

Indurating furnace means a furnace where unfired taconite pellets, called green balls, are hardened at high temperatures to produce fired pellets for use in a blast furnace. Types of indurating furnaces include straight gate and grate kiln furnaces.

Industrial greenhouse gases means nitrous oxide or any fluorinated greenhouse gas.

In-line kiln/raw mill means a system in a portland cement production process where a dry kiln system is integrated with the raw mill so that all or a portion of the kiln exhaust gases are used to perform the drying operation of the raw mill, with no auxiliary heat source used. In this system the kiln is capable of operating without the raw mill operating, but the raw mill cannot operate without the kiln gases, and consequently, the raw mill does not generate a separate exhaust gas stream.

Isobutane is a paraffinic branch chain hydrocarbon with molecular formula C_4H_{10}.

Isobutylene is an olefinic branch chain hydrocarbon with molecular formula C_4H_8.

Kerosene is a light petroleum distillate with a maximum distillation temperature of 400 °F at the 10-percent recovery point, a final maximum boiling point of 572 °F, a minimum flash point of 100 °F, and a maximum freezing point of −22 °F. Included are No. 1–K and No. 2–K, distinguished by maximum sulfur content (0.04 and 0.30 percent of total mass, respectively), as well as all other grades of kerosene called range or stove oil. Excluded is kerosene-type jet fuel (see definition herein).

Kerosene-type jet fuel means a kerosene-based product used in commercial and military turbojet and turboprop aircraft. The product has a maximum distillation temperature of 400 °F at the 10 percent recovery point and a final maximum boiling point of 572 °F. Included are Jet A, Jet A–1, JP–5, and JP–8.

Kiln means an oven, furnace, or heated enclosure used for thermally processing a mineral or mineral-based substance.

Landfill means an area of land or an excavation in which wastes are placed for permanent disposal and that is not a land application unit, surface impoundment, injection well, or waste pile as those terms are defined under 40 CFR 257.2.

Landfill gas means gas produced as a result of anaerobic decomposition of waste materials in the landfill. Landfill gas generally contains 40 to 60 percent methane on a dry basis, typically less than 1 percent non-methane organic chemicals, and the remainder being carbon dioxide.

Lime is the generic term for a variety of chemical compounds that are produced by the calcination of limestone or dolomite. These products include but are not limited to calcium oxide, high-calcium quicklime, calcium hydroxide, hydrated lime, dolomitic quicklime, and dolomitic hydrate.

Liquid/Slurry means a manure management component in which manure is stored as excreted or with some minimal addition of water to facilitate handling and is stored in either tanks or earthen ponds, usually for periods less than one year.

Lubricants include all grades of lubricating oils, from spindle oil to cylinder oil to those used in greases. Petroleum lubricants may be produced from distillates or residues.

Makeup chemicals means carbonate chemicals (e.g., sodium and calcium carbonates) that are added to the chemical recovery areas of chemical pulp mills to replace chemicals lost in the process.

Manure composting means the biological oxidation of a solid waste including manure usually with bedding or another organic carbon source typically at thermophilic temperatures produced by microbial heat production. There are four types of composting employed for manure management: Static, in vessel, intensive windrow and passive windrow. Static composting typically occurs in an enclosed channel, with forced aeration and continuous mixing. In vessel composting occurs in piles with forced aeration but no mixing. Intensive windrow composting occurs in windrows with regular turning for mixing and aeration. Passive windrow composting occurs in windrows with infrequent turning for mixing and aeration.

Maximum rated heat input capacity means the hourly heat input to a unit (in mmBtu/hr), when it combusts the maximum amount of fuel per hour that it is capable of combusting on a steady state basis, as of the initial installation of the unit, as specified by the manufacturer.

Maximum rated input capacity means the maximum charging rate of a municipal waste combustor unit expressed in tons per day of municipal solid waste combusted, calculated according to the procedures under 40 CFR 60.58b(j).

Mcf means thousand cubic feet.

Methane conversion factor means the extent to which the CH_4 producing capacity (B_o) is realized in each type of treatment and discharge pathway and system. Thus, it is an indication of the degree to which the system is anaerobic.

Methane correction factor means an adjustment factor applied to the methane generation rate to account for portions of the landfill that remain aerobic. The methane correction factor can be considered the fraction of the total landfill waste volume that is ultimately disposed of in an anaerobic state. Managed landfills that have soil or other cover materials have a methane correction factor of 1.

Methanol (CH_3OH) is an alcohol as described in ''Oxygenates.''

Midgrade gasoline has an octane rating greater than or equal to 88 and less than or equal to 90. This definition applies to the midgrade categories of Conventional-Summer, Conventional-Winter, Reformulated-Summer, and Reformulated-Winter. For midgrade categories of RBOB-Summer, RBOB-Winter, CBOB-Summer, and CBOB-Winter, this definition refers to the expected octane rating of the finished gasoline after oxygenate has been added to the RBOB or CBOB.

Miscellaneous products include all refined petroleum products not defined elsewhere. It includes, but is not limited to, naphtha-type jet fuel (Jet B and JP–4), petrolatum lube refining by-products (aromatic extracts and tars), absorption oils, ram-jet fuel, petroleum rocket fuels, synthetic natural gas feedstocks, waste feedstocks, and specialty oils. It excludes organic waste sludges, tank bottoms, spent catalysts, and sulfuric acid.

MMBtu means million British thermal units.

Motor gasoline (finished) means a complex mixture of volatile hydrocarbons, with or without additives, suitably blended to be used in spark ignition engines. Motor gasoline includes conventional gasoline, reformulated gasoline, and all types of oxygenated gasoline. Gasoline also has seasonal variations in an effort to control ozone levels. This is achieved by lowering the Reid Vapor Pressure (RVP) of gasoline during the summer driving season. Depending on the region of the country the RVP is lowered to below 9.0 psi or 7.8 psi. The RVP may be further lowered by state regulations.

Mscf means million standard cubic feet.

MTBE (methyl tertiary butyl ether, $(CH_3)_3COCH_3$) is an ether as described in ''Oxygenates.''

Municipal solid waste landfill or MSW landfill means an entire disposal facility in a contiguous geographical space where household waste is placed in or on land. An MSW landfill may also receive other types of RCRA Subtitle D wastes (40 CFR 257.2) such as commercial solid waste, nonhazardous sludge, conditionally exempt small quantity generator waste, and industrial solid waste. Portions of an MSW landfill may be separated by access roads, public roadways, or other public right-of-ways. An MSW landfill may be publicly or privately owned.

Municipal solid waste or MSW means solid phase household, commercial/retail, and/or institutional waste, such as, but not limited to, yard waste and refuse.

N_2O means nitrous oxide.

Naphthas (< 401 °F) is a generic term applied to a petroleum fraction with an approximate boiling range between 122 °F and 400 °F. The naphtha fraction of crude oil is the raw material for gasoline and is composed largely of paraffinic hydrocarbons.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include, but are not limited to, methane, heavier hydrocarbons and carbon dioxide. Natural gas may be field quality (which varies widely) or pipeline quality. For the purposes of this subpart, the definition of natural gas includes similarly constituted fuels such as field production gas, process gas, and fuel gas.

Natural gas liquids (NGLs) means those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption, or other methods at lease separators and field facilities. Generally, such liquids consist of ethane, propane, butanes, and pentanes plus. Bulk NGLs refers to mixtures of NGLs that are sold or delivered as undifferentiated product from natural gas processing plants.

Natural gasoline means a mixture of liquid hydrocarbons (mostly pentanes and heavier hydrocarbons) extracted from natural gas. It includes isopentane.

NIST means the United States National Institute of Standards and Technology.

Nitric acid production line means a series of reactors and absorbers used to produce nitric acid.

Nitrogen excreted is the nitrogen that is excreted by livestock in manure and urine.

Non-crude feedstocks means any petroleum product or natural gas liquid that enters the refinery as a feedstock to be further refined or otherwise used on site.

Non-recovery coke oven battery means a group of ovens connected by common walls and operated as a unit, where coal undergoes destructive distillation under negative pressure to produce coke, and which is designed for the combustion of the coke oven gas from which by-products are not recovered.

Oil-fired unit means a stationary combustion unit that derives more than 50 percent of its annual heat input from the combustion of fuel oil, and the remainder of its annual heat input from the combustion of natural gas or other gaseous fuels.

Open-ended valve or lines (OELs) means any valve, except pressure relief valves, having one side of the valve seat in contact with process fluid and one side open to atmosphere, either directly or through open piping.

Operating hours means the duration of time in which a process or process unit is utilized; this excludes shutdown, maintenance, and standby.

Operational change means, for purposes of § 98.3(b), a change in the type of feedstock or fuel used, a change in operating hours, or a change in process production rate.

Operator means any person who operates or supervises a facility or supplier.

Other oils (> 401 °F) are oils with a boiling range equal to or greater than 401 °F that are generally intended for use as a petrochemical feedstock and are not defined elsewhere.

Owner means any person who has legal or equitable title to, has a leasehold interest in, or control of a facility or supplier, except a person whose legal or equitable title to or leasehold interest in the facility or supplier arises solely because the person is a limited partner in a partnership that has legal or equitable title to, has a leasehold interest in, or control of the facility or supplier shall not be considered an ''owner'' of the facility or supplier.

Oxygenates means substances which, when added to gasoline, increase the oxygen content of the gasoline. Common oxygenates are ethanol, methyl tertiary butyl ether (MTBE), ethyl tertiary butyl ether (ETBE), tertiary amyl methyl ether (TAME), diisopropyl ether (DIPE), and methanol.

Pasture/Range/Paddock means the manure from pasture and range grazing animals is allowed to lie as deposited, and is not managed.

Pentanes plus, or C5+, is a mixture of hydrocarbons that is a liquid at ambient temperature and pressure, and consists mostly of pentanes (five carbon chain) and higher carbon number hydrocarbons. Pentanes plus includes, but is not limited to, normal pentane, isopentane, hexanes-plus (natural gasoline), and plant condensate.

Perfluorocarbons or PFCs means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

Petrochemical means methanol, acrylonitrile, ethylene, ethylene oxide, ethylene dichloride, and any form of carbon black.

Petrochemical feedstocks means feedstocks derived from petroleum for the manufacture of chemicals, synthetic rubber, and a variety of plastics. This category is usually divided into naphthas less than 401 °F and other oils greater than 401 °F.

Petroleum means oil removed from the earth and the oil derived from tar sands and shale.

Petroleum coke means a black solid residue, obtained mainly by cracking and carbonizing of petroleum derived feedstocks, vacuum bottoms, tar and pitches in processes such as delayed coking or fluid coking. It consists mainly of carbon (90 to 95 percent), has low ash content, and may be used as a feedstock in coke ovens. This product is also known as marketable coke or catalyst coke.

Petroleum product means all refined and semi-refined products that are produced at a refinery by processing crude oil and other petroleum-based feedstocks, including petroleum products derived from co-processing biomass and petroleum feedstock together, but not including plastics or plastic products. Petroleum products may be combusted for energy use, or they may be used either for non-energy processes or as non-energy products. The definition of petroleum product for importers and exporters excludes waxes.

Pit storage below animal confinement (deep pits) means the collection and storage of manure typically below a slatted floor in an enclosed animal confinement facility. This usually occurs with little or no added water for periods less than one year.

Portable means designed and capable of being carried or moved from one location to another. Indications of portability include but are not limited to wheels, skids, carrying handles, dolly, trailer, or platform. Equipment is not portable if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The equipment or a replacement resides at the same location for more than 12 consecutive months.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least two years, and operates at that facility for at least three months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the portable residence time requirements of this definition.

Poultry manure with litter means a manure management system component that is similar to cattle and swine deep bedding except usually not combined with a dry lot or pasture. The system is typically used for poultry breeder flocks and for the production of meat type chickens (broiler) and other fowl.

Poultry manure without litter means a manure management system component that may manage manure in a liquid form, similar to open pits in enclosed animal confinement facilities. These systems may alternatively be designed and operated to dry manure as it accumulates. The latter is known as a high-rise manure management system and is a form of passive windrow manure composting when designed and operated properly.

Precision of a measurement at a specified level (e.g., one percent of full scale or one percent of the value measured) means that 95 percent of repeat measurements made by a device or technique are within the range bounded by the mean of the measurements plus or minus the specified level.

Premium grade gasoline is gasoline having an antiknock index, i.e., octane rating, greater than 90. This definition applies to the premium grade categories of Conventional-Summer, Conventional-Winter, Reformulated-Summer, and Reformulated-Winter. For premium grade categories of RBOB-Summer, RBOB-Winter, CBOB-Summer, and CBOB-Winter, this definition refers to the expected octane rating of the finished gasoline after oxygenate has been added to the RBOB or CBOB.

Pressed and blown glass means glass which is pressed, blown, or both, into products such as light bulbs, glass fiber, technical glass, and other products listed in NAICS 327212.

Pressure relief device or pressure relief valve or pressure safety valve means a safety device used to prevent operating pressures from exceeding the maximum allowable working pressure of the process equipment. A common pressure relief device is but not limited to a spring-loaded pressure relief valve. Devices that are actuated either by a pressure of less than or equal to 2.5 psig or by a vacuum are not pressure relief devices.

Process emissions means the emissions from industrial processes (e.g., cement production, ammonia production) involving chemical or physical transformations other than fuel combustion. For example, the calcination of carbonates in a kiln during cement production or the oxidation of methane in an ammonia process results in the release of process CO_2 emissions to the atmosphere. Emissions from fuel combustion to provide process heat are not part of process emissions, whether the combustion is internal or external to the process equipment.

Process unit means the equipment assembled and connected by pipes and ducts to process raw materials and to manufacture either a final product or an intermediate used in the onsite production of other products. The process unit also includes the purification of recovered byproducts.

Process vent means means a gas stream that: Is discharged through a conveyance to the atmosphere either directly or after passing through a control device; originates from a unit operation, including but not limited to reactors (including reformers, crackers, and furnaces, and separation equipment for products and recovered byproducts); and contains or has the potential to contain GHG that is generated in the process. Process vent does not include safety device discharges, equipment leaks, gas streams routed to a fuel gas system or to a flare, discharges from storage tanks.

Propane is a paraffinic hydrocarbon with molecular formula C_3H_8.

Propylene is an olefinic hydrocarbon with molecular formula C_3H_6.

Pulp mill lime kiln means the combustion units (e.g., rotary lime kiln or fluidized bed calciner) used at a kraft or soda pulp mill to calcine lime mud, which consists primarily of calcium carbonate, into quicklime, which is calcium oxide.

Pushing means the process of removing the coke from the coke oven at the end of the coking cycle. Pushing begins when coke first begins to fall from the oven into the quench car and ends when the quench car enters the quench tower.

Raw mill means a ball and tube mill, vertical roller mill or other size reduction equipment, that is not part of an in-line kiln/raw mill, used to grind feed to the appropriate size. Moisture may be added or removed from the feed during the grinding operation. If the raw mill is used to remove moisture from feed materials, it is also, by definition, a raw material dryer. The raw mill also includes the air separator associated with the raw mill.

RBOB-Summer (reformulated blendstock for oxygenate blending) means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of Reformulated-Summer.

RBOB-Winter (reformulated blendstock for oxygenate blending) means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of Reformulated-Winter.

Reformulated-Summer refers to finished gasoline formulated for use in motor vehicles, the composition and properties of which meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR 80.40 and 40 CFR 80.41, and summer RVP standards required under 40 CFR 80.27 or as specified by the state. Reformulated gasoline excludes Reformulated Blendstock for Oxygenate Blending (RBOB) as well as other blendstock.

Reformulated-Winter refers to finished gasoline formulated for use in motor vehicles, the composition and properties of which meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR 80.40 and 40 CFR 80.41, but which do not meet summer RVP standards required under 40 CFR 80.27 or as specified by the state. **Note:** This category includes Oxygenated Fuels Program Reformulated Gasoline (OPRG). Reformulated gasoline excludes Reformulated Blendstock for Oxygenate Blending (RBOB) as well as other blendstock.

Regular grade gasoline is gasoline having an antiknock index, i.e., octane rating, greater than or equal to 85 and less than 88. This definition applies to the regular grade categories of Conventional-Summer, Conventional-Winter, Reformulated-Summer, and Reformulated-Winter. For regular grade categories of RBOB-Summer, RBOB-Winter, CBOB-Summer, and CBOB-Winter, this definition refers to the expected octane rating of the finished gasoline after oxygenate has been added to the RBOB or CBOB.

Rendered animal fat, or tallow, means fats extracted from animals which are generally used as a feedstock in making biodiesel.

Research and development means those activities conducted in process units or at laboratory bench-scale settings whose purpose is to conduct research and development for new processes, technologies, or products and whose purpose is not for the manufacture of products for commercial sale, except in a *de minimis* manner.

Residual Fuel Oil No. 5 (Navy Special) is a classification for the heavier fuel oil generally used in steam powered vessels in government service and inshore power plants. It has a minimum flash point of 131 °F.

Residual Fuel Oil No. 6 (a.k.a. Bunker C) is a classification for the heavier fuel oil generally used for the production of electric power, space heating, vessel bunkering and various industrial purposes. It has a minimum flash point of 140 °F.

Residuum is residue from crude oil after distilling off all but the heaviest components, with a boiling range greater than 1,000 °F.

Road oil is any heavy petroleum oil, including residual asphaltic oil used as a dust palliative and surface treatment on roads and highways. It is generally produced in six grades, from 0, the most liquid, to 5, the most viscous.

Rotary lime kiln means a unit with an inclined rotating drum that is used to produce a lime product from limestone by calcination.

Safety device means a closure device such as a pressure relief valve, frangible disc, fusible plug, or any other type of device which functions exclusively to prevent physical damage or permanent deformation to a unit or its air emission control equipment by venting gases or vapors directly to the atmosphere during unsafe conditions resulting from an unplanned, accidental, or emergency event. A safety device is not used for routine venting of gases or vapors from the vapor headspace underneath a cover such as during filling of the unit or to adjust the pressure in response to normal daily diurnal ambient temperature fluctuations. A safety device is designed to remain in a closed position during normal operations and open only when the internal pressure, or another relevant parameter, exceeds the device threshold setting applicable to the air emission control equipment as determined by the owner or operator based on manufacturer recommendations, applicable regulations, fire protection and prevention codes and practices, or other requirements for the safe handling of flammable, combustible, explosive, reactive, or hazardous materials.

Semi-refined petroleum product means all oils requiring further processing. Included in this category are unfinished oils which are produced by the partial refining of crude oil and include the following: Naphthas and lighter oils; kerosene and light gas oils; heavy gas oils; and residuum, and all products that require further processing or the addition of blendstocks.

Sendout means, in the context of a local distribution company, the total deliveries of natural gas to customers over a specified time interval (typically hour, day, month, or year). Sendout is the sum of gas received through the city gate, gas withdrawn from on-system storage or peak shaving plants, and gas produced and delivered into the distribution system; and is net of any natural gas injected into on-system storage. It comprises gas sales, exchange, deliveries, gas used by company, and unaccounted for gas. Sendout is measured at the city gate station, and other on-system receipt points from storage, peak shaving, and production.

Sensor means a device that measures a physical quantity/quality or the change in a physical quantity/quality, such as temperature, pressure, flow rate, pH, or liquid level.

SF_6 means sulfur hexafluoride.

Shutdown means the cessation of operation of an emission source for any purpose.

Silicon carbide means an artificial abrasive produced from silica sand or quartz and petroleum coke.

Sinter process means a process that produces a fused aggregate of fine iron-bearing materials suited for use in a blast furnace. The sinter machine is composed of a continuous traveling grate that conveys a bed of ore fines and other finely divided iron-bearing material and fuel (typically coke breeze), a burner at the feed end of the grate for ignition, and a series of downdraft windboxes along the length of the strand to support downdraft combustion and heat sufficient to produce a fused sinter product.

Site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically located.

Smelting furnace means a furnace in which lead-bearing materials, carbon-containing reducing agents, and fluxes are melted together to form a molten mass of material containing lead and slag.

Solid storage is the storage of manure, typically for a period of several months, in unconfined piles or stacks. Manure is able to be stacked due to the presence of a sufficient amount of bedding material or loss of moisture by evaporation.

Sour gas means any gas that contains significant concentrations of hydrogen sulfide. Sour gas may include untreated fuel gas, amine stripper off-gas, or sour water stripper gas.

Special naphthas means all finished products with the naphtha boiling range (290 ° to 470 °F) that are generally used as paint thinners, cleaners or solvents. These products are refined to a specified flash point. Special naphthas include all commercial hexane and cleaning solvents conforming to ASTM Specification D1836–07, Standard Specification for Commercial Hexanes, and D235–02 (Reapproved 2007), Standard Specification for Mineral Spirits (Petroleum Spirits) (Hydrocarbon Dry Cleaning Solvent), respectively. Naphthas to be blended or marketed as motor gasoline or aviation gasoline, or that are to be used as petrochemical and synthetic natural gas (SNG) feedstocks are excluded.

Spent liquor solids means the dry weight of the solids in the spent pulping liquor that enters the chemical recovery furnace or chemical recovery combustion unit.

Spent pulping liquor means the residual liquid collected from on-site pulping operations at chemical pulp facilities that is subsequently fired in chemical recovery furnaces at kraft and soda pulp facilities or chemical recovery combustion units at sulfite or semi-chemical pulp facilities.

Standard conditions or standard temperature and pressure (STP) means 68 degrees Fahrenheit and 14.7 pounds per square inch absolute.

Steam reforming means a catalytic process that involves a reaction between natural gas or other light hydrocarbons and steam. The result is a mixture of hydrogen, carbon monoxide, carbon dioxide, and water.

Still gas means any form or mixture of gases produced in refineries by distillation, cracking, reforming, and other processes. The principal constituents are methane, ethane, ethylene, normal butane, butylene, propane, and propylene.

Storage tank means a vessel (excluding sumps) that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of non-earthen materials (e.g., wood, concrete, steel, plastic) that provide structural support.

Sulfur recovery plant means all process units which recover sulfur or produce sulfuric acid from hydrogen sulfide (H_2S) and/or sulfur dioxide (SO_2) from a common source of sour gas at a petroleum refinery. The sulfur recovery plant also includes sulfur pits used to store the recovered sulfur product, but it does not include secondary sulfur storage vessels or loading facilities downstream of the sulfur pits. For example, a Claus sulfur recovery plant includes: Reactor furnace and waste heat boiler, catalytic reactors, sulfur pits, and, if present, oxidation or reduction control systems, or incinerator, thermal oxidizer, or similar combustion device. Multiple sulfur recovery units are a single sulfur recovery plant only when the units share the same source of sour gas. Sulfur recovery units that receive source gas from completely segregated sour gas treatment systems are separate sulfur recovery plants.

Supplemental fuel means a fuel burned within a petrochemical process that is not produced within the process itself.

Supplier means a producer, importer, or exporter of a fossil fuel or an industrial greenhouse gas.

Taconite iron ore processing means an industrial process that separates and concentrates iron ore from taconite, a low grade iron ore, and heats the taconite in an indurating furnace to produce taconite pellets that are used as the primary feed material for the production of iron in blast furnaces at integrated iron and steel plants.

TAME means tertiary amyl methyl ether, $(CH_3)_2(C_2H_5)COCH_3$).

Trace concentrations means concentrations of less than 0.1 percent by mass of the process stream.

Transform means to use and entirely consume (except for trace concentrations) nitrous oxide or fluorinated GHGs in the manufacturing of other chemicals for commercial purposes. Transformation does not include burning of nitrous oxide.

Transshipment means the continuous shipment of nitrous oxide or a fluorinated GHG from a foreign state of origin through the United States or its territories to a second foreign state of final destination, as long as the shipment does not enter into United States jurisdiction. A transshipment, as it moves through the United States or its territories, cannot be re-packaged, sorted or otherwise changed in condition.

Trona means the raw material (mineral) used to manufacture soda ash; hydrated sodium bicarbonate carbonate (e.g., $Na2CO_3.NaHCO_3.2H_2O$).

Ultimate analysis means the determination of the percentages of carbon, hydrogen, nitrogen, sulfur, and chlorine and (by difference) oxygen in the gaseous products and ash after the complete combustion of a sample of an organic material.

Unfinished oils are all oils requiring further processing, except those requiring only mechanical blending.

United States means the 50 states, the District of Columbia, and U.S. possessions and territories.

Unstabilized crude oil means, for the purposes of this part, crude oil that is pumped from the well to a pipeline or pressurized storage vessel for transport to the refinery without intermediate storage in a storage tank at atmospheric pressures. Unstabilized crude oil is characterized by having a true vapor pressure of 5 pounds per square inch absolute (psia) or greater.

Valve means any device for halting or regulating the flow of a liquid or gas through a passage, pipeline, inlet, outlet, or orifice; including, but not limited to, gate, globe, plug, ball, butterfly and needle valves.

Vegetable oil means oils extracted from vegetation that are generally used as a feedstock in making biodiesel.

Volatile solids are the organic material in livestock manure and consist of both biodegradable and non-biodegradable fractions.

Waelz kiln means an inclined rotary kiln in which zinc-containing materials are charged together with a carbon reducing agent (e.g., petroleum coke, metallurgical coke, or anthracite coal).

Waxes means a solid or semi-solid material at 77 °F consisting of a mixture of hydrocarbons obtained or derived from petroleum fractions, or through a Fischer-Tropsch type process, in which the straight chained paraffin series predominates. This includes all marketable wax, whether crude or refined, with a congealing point between 80 (or 85) and 240 °F and a maximum oil content of 50 weight percent.

Wool fiberglass means fibrous glass of random texture, including fiberglass insulation, and other products listed in NAICS 327993.

You means an owner or operator subject to Part 98.

Zinc smelters means a facility engaged in the production of zinc metal, zinc oxide, or zinc alloy products from zinc sulfide ore concentrates, zinc calcine, or zinc-bearing scrap and recycled materials through the use of pyrometallurgical techniques involving the reduction and volatization of zinc-bearing feed materials charged to a furnace.

§ 98.7 What standardized methods are incorporated by reference into this part?

The materials listed in this section are incorporated by reference in the corresponding sections noted. These incorporations by reference were approved by the Director of Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. These materials are incorporated as they exist on the date of approval, and a notice of any change in the materials will be published in the **Federal Register**. The materials are available for purchase at the corresponding address in this section. The materials are available for inspection at the EPA Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue, NW., Washington, DC, phone (202) 566–1744 and at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html*.

(a) The following material is available for purchase from the Association of Fertilizer and Phosphate Chemists (AFPC), P.O. Box 1645, Bartow, Florida 33831, *http://afpc.net*.

(1) Phosphate Mining States Methods Used and Adopted by the Association of Fertilizer and Phosphate Chemists AFPC Manual 10th Edition 2009—Version 1.9, incorporation by reference (IBR) approved for § 98.264(a) and § 98.264(b).

(2) [Reserved]

(b) The following material is available for purchase from the American Gas Association (AGA), 400 North Capitol Street, NW., 4th Floor, Washington, DC 20001, (202) 824–7000, *http://www.aga.org*.

(1) AGA Report No. 3 Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 1: General Equations & Uncertainty Guidelines (1990), incorporation by reference (IBR) approved for § 98.34(b) and § 98.244(b).

(2) AGA Report No. 3 Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 2: Specification and Installation Requirements (2000), IBR approved for § 98.34(b) and § 98.244(b).

(3) AGA Report No. 11 Measurement of Natural Gas by Coriolis Meter (2003), IBR approved for § 98.244(b) and § 98.254(c).

(4) AGA Transmission Measurement Committee Report No. 7 Measurement of Natural Gas by Turbine Meter (2006)/February, IBR approved for § 98.34(b) and § 98.244(b).

(c) The following material is available for purchase from the ASM International, 9639 Kinsman Road, Materials Park, OH 44073, (440) 338–5151, *http://www.asminternational.org*.

(1) ASM CS–104 UNS No. G10460—Alloy Digest April 1985 (Carbon Steel of Medium Carbon Content), incorporation by reference (IBR) approved for § 98.174(b).

(2) [Reserved]

(d) The following material is available for purchase from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, *http://www.asme.org*.

(1) ASME MFC–3M–2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi, incorporation by reference (IBR) approved for § 98.34(b), § 98.244(b), § 98.254(c), § 98.344(c), and § 98.364(e).

(2) ASME MFC–4M–1986 (Reaffirmed 1997) Measurement of Gas Flow by Turbine Meters, IBR approved for § 98.34(b), § 98.244(b), § 98.254(c), § 98.344(c), and § 98.364(e).

(3) ASME MFC–5M–1985 (Reaffirmed 1994) Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters, IBR approved for § 98.34(b) and § 98.244(b).

(4) ASME MFC–6M–1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters, IBR approved for § 98.34(b), § 98.244(b), § 98.254(c), § 98.344(c), and § 98.364(e).

(5) ASME MFC–7M–1987 (Reaffirmed 1992) Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles, IBR approved for § 98.34(b), § 98.244(b), § 98.254(c), § 98.344(c), and § 98.364(e).

(6) ASME MFC–9M–1988 (Reaffirmed 2001) Measurement of Liquid Flow in Closed Conduits by Weighing Method, IBR approved for § 98.34(b) and § 98.244(b).

(7) ASME MFC–11M–2006 Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters, IBR approved for § 98.244(b), § 98.254(c), and § 98.344(c).

(8) ASME MFC–14M–2003 Measurement of Fluid Flow Using Small Bore Precision Orifice Meters, IBR approved for § 98.244(b), § 98.254(c), § 98.344(c), and § 98.364(e).

(9) ASME MFC–16–2007 Measurement of Liquid Flow in Closed Conduits with Electromagnetic Flowmeters, IBR approved for § 98.244(b).

(10) ASME MFC–18M–2001 Measurement of Fluid Flow Using Variable Area Meters, IBR approved for § 98.244(b), § 98.254(c),§ 98.344(c), and § 98.364(e).

(11) ASME MFC–22–2007 Measurement of Liquid by Turbine Flowmeters, IBR approved for § 98.244(b).

(e) The following material is available for purchase from the American Society for Testing and Material (ASTM), 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B2959, (800) 262–1373, *http://www.astm.org*.

(1) ASTM C25–06 Standard Test Method for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime, incorporation by reference (IBR) approved for § 98.114(b), § 98.174(b), § 98.184(b), § 98.194(c), and § 98.334(b).

(2) ASTM C114–09 Standard Test Methods for Chemical Analysis of Hydraulic Cement, IBR approved for § 98.84(a), § 98.84(b), and § 98.84(c).

(3) ASTM D235–02 (Reapproved 2007) Standard Specification for Mineral Spirits (Petroleum Spirits) (Hydrocarbon Dry Cleaning Solvent), IBR approved for § 98.6.

(4) ASTM D240–02 (Reapproved 2007) Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for § 98.34(a) and § 98.254(e).

(5) ASTM D388–05 Standard Classification of Coals by Rank, IBR approved for § 98.6.

(6) ASTM D910–07a Standard Specification for Aviation Gasolines, IBR approved for § 98.6.

(7) ASTM D1298–99 (Reapproved 2005) Standard Test Method for Density,

Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method, IBR approved for § 98.33(a).

(8) ASTM D1826–94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for § 98.34(a) and § 98.254(e).

(9) ASTM D1836–07 Standard Specification for Commercial Hexanes, IBR approved for § 98.6.

(10) ASTM D1945–03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for § 98.34(b), § 98.74(c), § 98.164(b), § 98.244(b), § 98.254(d), and § 98.344(b).

(11) ASTM D1946–90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography, IBR approved for § 98.34(b), § 98.74(c), § 98.164(b), § 98.254(d), § 98.344(b), and § 98.364(c).

(12) ASTM D2013–07 Standard Practice for Preparing Coal Samples for Analysis, IBR approved for § 98.164(b).

(13) ASTM D2234/D2234M–07 Standard Practice for Collection of a Gross Sample of Coal, IBR approved for § 98.164(b).

(14) ASTM D2502–04 Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils From Viscosity Measurements, IBR approved for § 98.34(b) and § 98.74(c).

(15) ASTM D2503–92 (Reapproved 2007) Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure, IBR approved for § 98.34(b) and § 98.74(c).

(16) ASTM D2505–88 (Reapproved 2004)e1 Standard Test Method for Ethylene, Other Hydrocarbons, and Carbon Dioxide in High-Purity Ethylene by Gas Chromatography, IBR approved for § 98.244(b).

(17) ASTM D2597–94 (Reapproved 2004) Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography, IBR approved for § 98.164(b).

(18) ASTM D3176–89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke, IBR approved for § 98.74(c), § 98.164(b), § 98.244(b), § 98.254(i), § 98.284(c), § 98.284(d), § 98.314(c), § 98.314(d), and § 98.314(f).

(19) ASTM D3238–95 (Reapproved 2005) Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method, IBR approved for § 98.34(b), § 98.74(c), and § 98.164(b).

(20) ASTM D3588–98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, IBR approved for § 98.34(a) and § 98.254(e).

(21) ASTM D3682–01 (Reapproved 2006) Standard Test Method for Major and Minor Elements in Combustion Residues from Coal Utilization Processes, IBR approved for § 98.144(b).

(22) ASTM D4057–06 Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for § 98.164(b).

(23) ASTM D4177–95 (Reapproved 2005) Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for § 98.164(b).

(24) ASTM D4809–06 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), IBR approved for § 98.34(a) and § 98.254(e).

(25) ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, IBR approved for § 98.34(a) and § 98.254(e).

(26) ASTM D5291–02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, IBR approved for § 98.34(b), § 98.74(c), § 98.164(b), § 98.244(b), § 98.254(i).

(27) ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal, IBR approved for § 98.34(b), § 98.74(c), § 98.114(b), § 98.164(b), § 98.174(b), § 98.184(b), § 98.244(b), § 98.254(i), § 98.274(b), § 98.284(c), § 98.284(d), § 98.314(c), § 98.314(d), § 98.314(f), and § 98.334(b).

(28) ASTM D5865–07a Standard Test Method for Gross Calorific Value of Coal and Coke, IBR approved for § 98.34(a).

(29) ASTM D6060–96 (Reapproved 2001) Standard Practice for Sampling of Process Vents With a Portable Gas Chromatograph, IBR approved for § 98.244(b).

(30) ASTM D6348–03 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, IBR approved for § 98.54(b) and § 98.224(b).

(31) ASTM D6609–08 Standard Guide for Part-Stream Sampling of Coal, IBR approved for § 98.164(b).

(32) ASTM D6751–08 Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, IBR approved for § 98.6.

(33) ASTM D6866–08 Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis, IBR approved for § 98.33(e), § 98.34(d), § 98.34(e), and § 98.36(e).

(34) ASTM D6883–04 Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles, IBR approved for § 98.164(b).

(35) ASTM D7430–08ae1 Standard Practice for Mechanical Sampling of Coal, IBR approved for § 98.164(b).

(36) ASTM D7459–08 Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources, IBR approved for § 98.33(e), § 98.34(d), § 98.34(e), and § 98.36(e).

(37) ASTM E359–00 (Reapproved 2005)e1 Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate), IBR approved for § 98.294(a) and § 98.294(b).

(38) ASTM E1019–08 Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel, Iron, Nickel, and Cobalt Alloys by Various Combustion and Fusion Techniques, IBR approved for § 98.174(b).

(39) ASTM E1747–95 (Reapproved 2005) Standard Guide for Purity of Carbon Dioxide Used in Supercritical Fluid Applications, IBR approved for 98.424(b).

(40) ASTM E1915–07a Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry, IBR approved for § 98.174(b).

(41) ASTM E1941–04 Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys, IBR approved for § 98.114(b), § 98.184(b), § 98.334(b).

(42) ASTM UOP539–97 Refinery Gas Analysis by Gas Chromatography, IBR approved for § 98.164(b), § 98.244(b), and § 98.254(d), and § 98.344(b).

(f) The following material is available for purchase from the Gas Processors Association (GPA), 6526 East 60th Street, Tulsa, Oklahoma 74143, (918) 493–3872, *http://www.gasprocessors.com*.

(1) GPA 2172–09 Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer, IBR approved for § 98.34(a).

(2) GPA 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, IBR approved for

§ 98.34(a), § 98.164(b), § 98.254(d), and § 98.344(b).

(g) The following material is available for purchase from the International Standards Organization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland, +41 22 749 01 11, *http://www.iso.org/iso/home.htm*.

(1) ISO 3170: Petroleum liquids—Manual sampling—Third Edition 2004–02–01, IBR approved for § 98.164(b).

(2) ISO 3171: Petroleum Liquids—Automatic pipeline sampling—Second Edition 1988–12–01, IBR approved for § 98.164(b).

(3) ISO 8316: Measurement of Liquid Flow in Closed Conduits— Method by Collection of the Liquid in a Volumetric Tank (1987–10–01)—First Edition, IBR approved for § 98.244(b).

(4) ISO/TR 15349–1: 1998, Unalloyed steel—Determination of low carbon content. Part 1: Infrared absorption method after combustion in an electric resistance furnace (by peak separation) (1998–10–15)—First Edition, IBR approved for § 98.174(b).

(5) ISO/TR 15349–3: 1998, Unalloyed steel—Determination of low carbon content. Part 3: Infrared absorption method after combustion in an electric resistance furnace (with preheating) (1998–10–15)—First Edition, IBR approved for § 98.174(b).

(h) The following material is available for purchase from the National Lime Association (NLA), 200 North Glebe Road, Suite 800, Arlington, Virginia 22203, (703) 243–5463, *http://www.lime.org*.

(1) CO_2 Emissions Calculation Protocol for the Lime Industry—English Units Version, February 5, 2008 Revision—National Lime Association, incorporation by reference (IBR) approved for § 98.194(c) and § 98.194(e).

(2) [Reserved]

(i) The following material is available for purchase from the National Institute of Standards and Technology (NIST), 100 Bureau Drive, Stop 1070, Gaithersburg, MD 20899–1070, (800) 877–8339, *http://www.nist.gov/index.html*.

(1) Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices, NIST Handbook 44 (2009), incorporation by reference (IBR) approved for § 98.244(b), § 98.254(h), and § 98.344(a).

(2) [Reserved]

(j) The following material is available for purchase from the Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Norcross, GA 30092, (800) 332–8686, *http://www.tappi.org*.

(1) T650 om-05 Solids Content of Black Liquor, TAPPI, incorporation by reference (IBR) approved for § 98.276(c) and § 98.277(d).

(2) T684 om-06 Gross Heating Value of Black Liquor, TAPPI, incorporation by reference (IBR) approved for § 98.274(b).

§ 98.8 What are the compliance and enforcement provisions of this part?

Any violation of any requirement of this part shall be a violation of the Clean Air Act, including section 114 (42 U.S.C. 7414). A violation includes but is not limited to failure to report GHG emissions, failure to collect data needed to calculate GHG emissions, failure to continuously monitor and test as required, failure to retain records needed to verify the amount of GHG emissions, and failure to calculate GHG emissions following the methodologies specified in this part. Each day of a violation constitutes a separate violation.

§ 98.9 Addresses.

All requests, notifications, and communications to the Administrator pursuant to this part, other than submittal of the annual GHG report, shall be submitted to the following address:

(a) For U.S. mail. Director, Climate Change Division, 1200 Pennsylvania Ave., NW., Mail Code: 6207J, Washington, DC 20460.

(b) For package deliveries. Director, Climate Change Division, 1310 L St, NW., Washington, DC 20005.

TABLE A–1 TO SUBPART A OF PART 98—GLOBAL WARMING POTENTIALS

[100-Year Time Horizon]

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
Carbon dioxide	124–38–9	CO_2	1
Methane	74–82–8	CH_4	21
Nitrous oxide	10024–97–2	N_2O	310
HFC–23	75–46–7	CHF_3	11,700
HFC–32	75–10–5	CH_2F_2	650
HFC–41	593–53–3	CH_3F	150
HFC–125	354–33–6	C_2HF_5	2,800
HFC–134	359–35–3	$C_2H_2F_4$	1,000
HFC–134a	811–97–2	CH_2FCF_3	1,300
HFC–143	430–66–0	$C_2H_3F_3$	300
HFC–143a	420–46–2	$C_2H_3F_3$	3,800
HFC–152	624–72–6	CH_2FCH_2F	53
HFC–152a	75–37–6	CH_3CHF_2	140
HFC–161	353–36–6	CH_3CH_2F	12
HFC–227ea	431–89–0	C_3HF_7	2,900
HFC–236cb	677–56–5	$CH_2FCF_2CF_3$	1,340
HFC–236ea	431–63–0	CHF_2CHFCF_3	1,370
HFC–236fa	690–39–1	$C_3H_2F_6$	6,300
HFC–245ca	679–86–7	$C_3H_3F_5$	560
HFC–245fa	460–73–1	$CHF_2CH_2CF_3$	1,030
HFC–365mfc	406–58–6	$CH_3CF_2CH_2CF_3$	794
HFC–43–10mee	138495–42–8	$CF_3CFHCFHCF_2CF_3$	1,300
Sulfur hexafluoride	2551–62–4	SF_6	23,900
Trifluoromethyl sulphur pentafluoride	373–80–8	SF_5CF_3	17,700
Nitrogen trifluoride	7783–54–2	NF_3	17,200
PFC–14 (Perfluoromethane)	75–73–0	CF_4	6,500
PFC–116 (Perfluoroethane)	76–16–4	C_2F_6	9,200
PFC–218 (Perfluoropropane)	76–19–7	C_3F_8	7,000

TABLE A–1 TO SUBPART A OF PART 98—GLOBAL WARMING POTENTIALS—Continued

[100-Year Time Horizon]

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
Perfluorocyclopropane	931–91–9	$C\text{-}C_3F_6$	17,340
PFC–3–1–10 (Perfluorobutane)	355–25–9	C_4F_{10}	7,000
Perfluorocyclobutane	115–25–3	$C\text{-}C_4F_8$	8,700
PFC–4–1–12 (Perfluoropentane)	678–26–2	C_5F_{12}	7,500
PFC–5–1–14 (Perfluorohexane)	355–42–0	C_6F_{14}	7,400
PFC–9–1–18	306–94–5	$C_{10}F_{18}$	7,500
HCFE–235da2 (Isoflurane)	26675–46–7	$CHF_2OCHClCF_3$	350
HFE–43–10pccc (H–Galden 1040x)	E1730133	$CHF_2OCF_2OC_2F_4OCHF_2$	1,870
HFE–125	3822–68–2	CHF_2OCF_3	14,900
HFE–134	1691–17–4	CHF_2OCHF_2	6,320
HFE–143a	421–14–7	CH_3OCF_3	756
HFE–227ea	2356–62–9	$CF_3CHFOCF_3$	1,540
HFE–236ca12 (HG–10)	78522–47–1	$CHF_2OCF_2OCHF_2$	2,800
HFE–236ea2 (Desflurane)	57041–67–5	$CHF_2OCHFCF_3$	989
HFE–236fa	20193–67–3	$CF_3CH_2OCF_3$	487
HFE–245cb2	22410–44–2	$CH_3OCF_2CF_3$	708
HFE–245fa1	84011–15–4	$CHF_2CH_2OCF_3$	286
HFE–245fa2	1885–48–9	$CHF_2OCH_2CF_3$	659
HFE–254cb2	425–88–7	$CH_3OCF_2CHF_2$	359
HFE–263fb2	460–43–5	$CF_3CH_2OCH_3$	11
HFE–329mcc2	67490–36–2	$CF_3CF_2OCF_2CHF_2$	919
HFE–338mcf2	156053–88–2	$CF_3CF_2OCH_2CF_3$	552
HFE–338pcc13 (HG–01)	188690–78–0	$CHF_2OCF_2CF_2OCHF_2$	1,500
HFE–347mcc3	28523–86–6	$CH_3OCF_2CF_2CF_3$	575
HFE–347mcf2	E1730135	$CF_3CF_2OCH_2CHF_2$	374
HFE–347pcf2	406–78–0	$CHF_2CF_2OCH_2CF_3$	580
HFE–356mec3	382–34–3	$CH_3OCF_2CHFCF_3$	101
HFE–356pcc3	160620–20–2	$CH_3OCF_2CF_2CHF_2$	110
HFE–356pcf2	E1730137	$CHF_2CH_2OCF_2CHF_2$	265
HFE–356pcf3	35042–99–0	$CHF_2OCH_2CF_2CHF_2$	502
HFE–365mcf3	378–16–5	$CF_3CF_2CH_2OCH_3$	11
HFE–374pc2	512–51–6	$CH_3CH_2OCF_2CHF_2$	557
HFE–449sl (HFE–7100)	163702–07–6	$C_4F_9OCH_3$	297
Chemical blend	163702–08–7	$(CF_3)_2CFCF_2OCH_3$	
HFE–569sf2 (HFE–7200)	163702–05–4	$C_4F_9OC_2H_5$	59
Chemical blend	163702–06–5	$(CF_3)_2CFCF_2OC_2H_5$	
Sevoflurane	28523–86–6	$CH_2FOCH(CF_3)_2$	345
HFE–356mm1	13171–18–1	$(CF_3)_2CHOCH_3$	27
HFE–338mmz1	26103–08–2	$CHF_2OCH(CF_3)_2$	380
(Octafluorotetramethy-lene)hydroxymethyl group	NA	$X\text{-}(CF_2)_4CH(OH)\text{-}X$	73
HFE–347mmy1	22052–84–2	$CH_3OCF(CF_3)_2$	343
Bis(trifluoromethyl)-methanol	920–66–1	$(CF_3)_2CHOH$	195
2,2,3,3,3-pentafluoropropanol	422–05–9	$CF_3CF_2CH_2OH$	42
PFPMIE	NA	$CF_3OCF(CF_3)CF_2OCF_2OCF_3$	10,300

NA = not available.

TABLE A–2 TO SUBPART A OF PART 98—UNITS OF MEASURE CONVERSIONS

To convert from	To	Multiply by
Kilograms (kg)	Pounds (lbs)	2.20462
Pounds (lbs)	Kilograms (kg)	0.45359
Pounds (lbs)	Metric tons	4.53592×10^{-4}
Short tons	Pounds (lbs)	2,000
Short tons	Metric tons	0.90718
Metric tons	Short tons	1.10231
Metric tons	Kilograms (kg)	1,000
Cubic meters (m^3)	Cubic feet (ft^3)	35.31467
Cubic feet (ft^3)	Cubic meters (m^3)	0.028317
Gallons (liquid, US)	Liters (l)	3.78541
Liters (l)	Gallons (liquid, US)	0.26417
Barrels of Liquid Fuel (bbl)	Cubic meters (m^3)	0.15891
Cubic meters (m^3)	Barrels of Liquid Fuel (bbl)	6.289
Barrels of Liquid Fuel (bbl)	Gallons (liquid, US)	42
Gallons (liquid, US)	Barrels of Liquid Fuel (bbl)	0.023810
Gallons (liquid, US)	Cubic meters (m^3)	0.0037854
Liters (l)	Cubic meters (m^3)	0.001

TABLE A–2 TO SUBPART A OF PART 98—UNITS OF MEASURE CONVERSIONS—Continued

To convert from	To	Multiply by
Feet (ft)	Meters (m)	0.3048
Meters (m)	Feet (ft)	3.28084
Miles (mi)	Kilometers (km)	1.60934
Kilometers (km)	Miles (mi)	0.62137
Square feet (ft^2)	Acres	2.29568×10^{-5}
Square meters (m^2)	Acres	2.47105×10^{-4}
Square miles (mi^2)	Square kilometers (km^2)	2.58999
Degrees Celsius (°C)	Degrees Fahrenheit (°F)	°C = (5⁄9) × (°F − 32)
Degrees Fahrenheit (°F)	Degrees Celsius (°C)	°F = (9⁄5) × °C + 32
Degrees Celsius (°C)	Kelvin (K)	K = °C + 273.15
Kelvin (K)	Degrees Rankine (°R)	1.8
Joules	Btu	9.47817×10^{-4}
Btu	MMBtu	1×10^{-6}
Pascals (Pa)	Inches of Mercury (in Hg)	2.95334×10^{-4}
Inches of Mercury (inHg)	Pounds per square inch (psi)	0.49110
Pounds per square inch (psi)	Inches of Mercury (in Hg)	2.03625

Subpart B—[Reserved]

Subpart C—General Stationary Fuel Combustion Sources

§ 98.30 Definition of the source category.

(a) Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources include, but are not limited to, boilers, simple and combined-cycle combustion turbines, engines, incinerators, and process heaters.

(b) This source category does not include:

(1) Portable equipment, as defined in § 98.6.

(2) Emergency generators and emergency equipment, as defined in § 98.6.

(3) Irrigation pumps at agricultural operations.

(4) Flares, unless otherwise required by provisions of another subpart of 40 CFR part 98 to use methodologies in this subpart.

(5) Electricity generating units that are subject to subpart D of this part.

(c) For a unit that combusts hazardous waste (as defined in 40 CFR 261.3), reporting of GHG emissions is not required unless either of the following conditions apply:

(1) Continuous emission monitors (CEMS) are used to quantify CO_2 mass emissions.

(2) Any fuel listed in Table C–1 of this subpart is also combusted in the unit. In this case, report GHG emissions from combustion of all fuels listed in Table C–1 of this subpart.

§ 98.31 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains one or more stationary fuel combustion sources and the facility meets the applicability requirements of either §§ 98.2(a)(1), 98.2(a)(2), or 98.2(a)(3).

§ 98.32 GHGs to report.

You must report CO_2, CH_4, and N_2O mass emissions from each stationary fuel combustion unit.

§ 98.33 Calculating GHG emissions.

You must calculate CO_2 emissions according to paragraph (a) of this section, and calculate CH_4 and N_2O emissions according to paragraph (c) of this section.

(a) *CO_2 emissions from fuel combustion.* Calculate CO_2 emissions by using one of the four calculation methodologies in this paragraph (a) subject to the conditions, requirements, and restrictions set forth in paragraph (b) of this section. If you co-fire biomass fuels with fossil fuels, report CO_2 emissions from the combustion of biomass separately using the methods in paragraph (e) of this section.

(1) *Tier 1 Calculation Methodology.* Calculate the annual CO_2 mass emissions for each type of fuel by using Equation C–1 of this section.

$$CO_2 = 1\,x\,10^{-3} * Fuel * HHV * EF \qquad \text{(Eq. C-1)}$$

Where:

CO_2 = Annual CO_2 mass emissions for the specific fuel type (metric tons).

Fuel = Mass or volume of fuel combusted per year, from company records as defined in § 98.6 (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

HHV = Default high heat value of the fuel, from Table C–1 of this subpart (mmBtu per mass or mmBtu per volume, as applicable).

EF = Fuel-specific default CO_2 emission factor, from Table C–1 of this subpart (kg CO_2/mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(2) *Tier 2 Calculation Methodology.* Calculate the annual CO_2 mass emissions for each type of fuel by using either Equation C2a or C2c of this section, as appropriate.

(i) Equation C–2a of this section applies to any type of fuel listed in Table C–1 of the subpart, except for municipal solid waste (MSW). For MSW combustion, use Equation C–2c of this section.

$$CO_2 = 1\,x\,10^{-3} * Fuel * HHV * EF \qquad \text{(Eq. C-2a)}$$

Where:

CO_2 = Annual CO_2 mass emissions for a specific fuel type (metric tons).

Fuel = Mass or volume of the fuel combusted during the year, from company records as defined in § 98.6 (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

HHV = Annual average high heat value of the fuel from all valid samples for the year (mmBtu per mass or volume). The average HHV shall be calculated according to the requirements of paragraph (a)(2)(ii) of this section.

EF = Fuel-specific default CO_2 emission factor, from Table C–1 of this subpart (kg CO_2/mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(ii) The minimum number of HHV samples for determining annual average HHV is specified (e.g., monthly, quarterly, semi-annually, or by lot) in § 98.34. The method for computing the annual average HHV is a function of how frequently you perform or receive from the fuel supplier the results of fuel sampling for HHV. The method is specified in paragraph (a)(2)(ii)(A) or (a)(2)(ii)(B) of this section, as applicable.

(A) If the results of fuel sampling are received monthly or more frequently, then the annual average HHV shall be calculated using Equation C–2b of this section. If multiple HHV determinations are made in any month, average the values for the month arithmetically.

$$(HHV)_{annual} = \frac{\sum_{i=1}^{n} (HHV)_i * (Fuel)_i}{\sum_{i=1}^{n} (Fuel)_i} \qquad \text{(Eq. C-2b)}$$

Where:

$(HHV)_{annual}$ = Weighted annual average high heat value of the fuel (mmBtu per mass or volume).

$(HHV)_i$ = High heat value of the fuel, for month "i" (mmBtu per mass or volume).

$(Fuel)_i$ = Mass or volume of the fuel combusted during month "i" (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

n = Number of months in the year that fuel is burned in the unit.

(B) If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be computed as the arithmetic average HHV for all values for the year (including valid samples and substitute data values under § 98.35).

(iii) For units that combust municipal solid waste (MSW) and that produce steam, use Equation C–2c of this section. Equation C–2c of this section may also be used for any other solid fuel listed in Table C–1 of this subpart provided that steam is generated by the unit.

$$CO_2 = 1\text{ x }10^{-3}\ \text{Steam} * \text{B} * \text{EF} \qquad \text{(Eq. C-2c)}$$

Where:

CO_2 = Annual CO_2 mass emissions from MSW or solid fuel combustion (metric tons).

Steam = Total mass of steam generated by MSW or solid fuel combustion during the reporting year (lb steam).

B = Ratio of the boiler's maximum rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).

EF = Fuel-specific default CO_2 emission factor, from Table C–1 of this subpart (kg CO_2/mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(3) *Tier 3 Calculation Methodology.* Calculate the annual CO_2 mass emissions for each fuel by using either Equation C3, C4, or C5 of this section, as appropriate.

(i) For a solid fuel, use Equation C–3 of this section.

$$CO_2 = \frac{44}{12} * \text{Fuel} * \text{CC} * 0.91 \qquad \text{(Eq. C-3)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the combustion of the specific solid fuel (metric tons).

Fuel = Annual mass of the solid fuel combusted, from company records as defined in § 98.6 (short tons).

CC = Annual average carbon content of the solid fuel (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.91 = Conversion factor from short tons to metric tons.

(ii) For a liquid fuel, use Equation C–4 of this section.

$$CO_2 = \frac{44}{12} * \text{Fuel} * \text{CC} * 0.001 \qquad \text{(Eq. C-4)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the combustion of the specific liquid fuel (metric tons).

Fuel = Annual volume of the liquid fuel combusted (gallons). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to § 98.3(i). Fuel billing meters may be used for this purpose. Tank drop measurements may also be used.

CC = Annual average carbon content of the liquid fuel (kg C per gallon of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

(iii) For a gaseous fuel, use Equation C–5 of this section.

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 \qquad \text{(Eq. C-5)}$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).

Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to § 98.3(i). Fuel billing meters may be used for this purpose.

CC = Annual average carbon content of the liquid fuel (kg C per gallon of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.

MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions, as defined in § 98.6).

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

(iv) Fuel flow meters that measure mass flow rates may be used for liquid fuels, provided that the fuel density is used to convert the readings to volumetric flow rates. The density shall be measured at the same frequency as the carbon content, using ASTM D1298–99 (Reapproved 2005) ''Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method'' (incorporated by reference, see § 98.7).

(v) The following default density values may be used for fuel oil, in lieu of using the ASTM method in paragraph (a)(3)(iv) of this section: 6.8 lb/gal for No. 1 oil; 7.2 lb/gal for No. 2 oil; 8.1 lb/gal for No. 6 oil.

(4) *Tier 4 Calculation Methodology.* Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using quality-assured data from continuous emission monitoring systems (CEMS).

(i) This methodology requires a CO_2 concentration monitor and a stack gas volumetric flow rate monitor, except as otherwise provided in paragraph (a)(4)(iv) of this section. Hourly measurements of CO_2 concentration and stack gas flow rate are converted to CO_2 mass emission rates in metric tons per hour.

(ii) When the CO_2 concentration is measured on a wet basis, Equation C–6 of this section is used to calculate the hourly CO_2 emission rates:

$$CO_2 = 5.18\,x\,10^{-7} * C_{CO2} * Q \qquad \text{(Eq. C-6)}$$

Where:

CO_2 = CO_2 mass emission rate (metric tons/hr).

C_{CO2} = Hourly average CO_2 concentration (% CO_2).

Q = Hourly average stack gas volumetric flow rate (scfh).

5.18×10^{-7} = Conversion factor (metric tons/scf/% CO_2).

(iii) If the CO_2 concentration is measured on a dry basis, a correction for the stack gas moisture content is required. You shall either continuously monitor the stack gas moisture content as described in § 75.11(b)(2) of this chapter or, for certain types of fuel, use a default moisture percentage from § 75.11(b)(1) of this chapter. For each unit operating hour, a moisture correction must be applied to Equation C–6 of this section as follows:

$$CO_2^* = CO_2\left(\frac{100 - \%H_2O}{100}\right) \qquad \text{(Eq. C-7)}$$

Where:

CO_2* = Hourly CO_2 mass emission rate, corrected for moisture (metric tons/hr).

CO_2 = Hourly CO_2 mass emission rate from Equation C-6 of this section, uncorrected (metric tons/hr).

%H_2O = Hourly moisture percentage in the stack gas (measured or default value, as appropriate).

(iv) An oxygen (O_2) concentration monitor may be used in lieu of a CO_2 concentration monitor to determine the hourly CO_2 concentrations, in accordance with Equation F–14a or F–14b (as applicable) in appendix F to 40 CFR part 75, if the effluent gas stream monitored by the CEMS consists solely of combustion products (i.e., no process CO_2 emissions are mixed with the combustion products) and if only fuels that are listed in Table 1 in section 3.3.5 of appendix F to 40 CFR part 75 are combusted in the unit. If the O_2 monitoring option is selected, the F-factors used in Equations F–14a and F–14b shall be determined according to section 3.3.5 or section 3.3.6 of appendix F to 40 CFR part 75, as applicable. If Equation F–14b is used, the hourly moisture percentage in the stack gas shall be either a measured value in accordance with § 75.11(b)(2) of this chapter, or, for certain types of fuel, a default moisture value from § 75.11(b)(1) of this chapter.

(v) Each hourly CO_2 mass emission rate from Equation C–6 or C–7 of this section is multiplied by the operating time to convert it from metric tons per hour to metric tons. The operating time is the fraction of the hour during which fuel is combusted (e.g., the unit operating time is 1.0 if the unit operates for the whole hour and is 0.5 if the unit operates for 30 minutes in the hour). For common stack configurations, the operating time is the fraction of the hour during which effluent gases flow through the common stack.

(vi) The hourly CO_2 mass emissions are then summed over each calendar quarter and the quarterly totals are summed to determine the annual CO_2 mass emissions.

(vii) If both biomass and fossil fuel are combusted during the year, determine and report the biogenic CO_2 mass emissions separately, as described in paragraph (e) of this section.

(5) *Alternative methods for units with continuous monitoring systems.* Units not subject to the Acid Rain Program that report data to EPA according to 40 CFR part 75 may use the alternative methods in this paragraph in lieu of using any of the four calculation methodology tiers.

(i) For a unit that combusts only natural gas and/or fuel oil, is not subject to the Acid Rain Program, monitors and reports heat input data year-round according to appendix D to 40 CFR part

75, but is not required by the applicable 40 CFR part 75 program to report CO_2 mass emissions data, calculate the annual CO_2 mass emissions for the purposes of this part as follows:

(A) Use the hourly heat input data from appendix D to 40 CFR part 75, together with Equation G–4 in appendix G to 40 CFR part 75 to determine the hourly CO_2 mass emission rates, in units of tons/hr;

(B) Use Equations F–12 and F–13 in appendix F to 40 CFR part 75 to calculate the quarterly and cumulative annual CO_2 mass emissions, respectively, in units of short tons; and

(C) Divide the cumulative annual CO_2 mass emissions value by 1.1 to convert it to metric tons.

(ii) For a unit that combusts only natural gas and/or fuel oil, is not subject to the Acid Rain Program, monitors and reports heat input data year-round according to 40 CFR 75.19 of this chapter but is not required by the applicable 40 CFR part 75 program to report CO_2 mass emissions data, calculate the annual CO_2 mass emissions for the purposes of this part as follows:

(A) Calculate the hourly CO_2 mass emissions, in units of short tons, using Equation LM–11 in 40 CFR 75.19(c)(4)(iii).

(B) Sum the hourly CO_2 mass emissions values over the entire reporting year to obtain the cumulative annual CO_2 mass emissions, in units of short tons.

(C) Divide the cumulative annual CO_2 mass emissions value by 1.1 to convert it to metric tons.

(iii) For a unit that is not subject to the Acid Rain Program, uses flow rate and CO_2 (or O_2) CEMS to report heat input data year-round according to 40 CFR part 75, but is not required by the applicable 40 CFR part 75 program to report CO_2 mass emissions data, calculate the annual CO_2 mass emissions as follows:

(A) Use Equation F–11 or F–2 (as applicable) in appendix F to 40 CFR part 75 to calculate the hourly CO_2 mass emission rates from the CEMS data. If an O_2 monitor is used, convert the hourly average O_2 readings to CO_2 using Equation F–14a or F–14b in appendix F to 40 CFR part 75 (as applicable), before applying Equation F–11 or F–2.

(B) Use Equations F–12 and F–13 in appendix F to 40 CFR part 75 to calculate the quarterly and cumulative annual CO_2 mass emissions, respectively, in units of short tons.

(C) Divide the cumulative annual CO_2 mass emissions value by 1.1 to convert it to metric tons.

(D) If both biomass and fossil fuel are combusted during the year, determine and report the biogenic CO_2 mass emissions separately, as described in paragraph (e) of this section.

(b) *Use of the four tiers.* Use of the four tiers of CO_2 emissions calculation methodologies described in paragraph (a) of this section is subject to the following conditions, requirements, and restrictions:

(1) The Tier 1 Calculation Methodology:

(i) May be used for any fuel listed in Table C–1 of this subpart that is combusted in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less.

(ii) May be used for MSW in a unit of any size that does not produce steam, if the use of Tier 4 is not required.

(iii) May be used for solid, gaseous, or liquid biomass fuels in a unit of any size provided that the fuel is listed in Table C–1 of this subpart.

(iv) May not be used if you routinely perform fuel sampling and analysis for the fuel high heat value (HHV) or routinely receive the results of HHV sampling and analysis from the fuel supplier at the minimum frequency specified in § 98.34(a), or at a greater frequency. In such cases, Tier 2 shall be used.

(2) The Tier 2 Calculation Methodology:

(i) May be used for the combustion of any type of fuel in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less provided that the fuel is listed in Table C–1 of this subpart.

(ii) May be used in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr for the combustion of pipeline quality natural gas and distillate fuel oil.

(iii) May be used for MSW in a unit of any size that produces steam, if the use of Tier 4 is not required.

(3) The Tier 3 Calculation Methodology:

(i) May be used for a unit of any size that combusts any type of fuel listed in Table C–1 of this subpart (except for MSW), unless the use of Tier 4 is required.

(ii) Shall be used for a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr that combusts any type of fuel listed in Table C–1 of this subpart (except MSW), unless either of the following conditions apply:

(A) The use of Tier 1 or 2 is permitted, as described in paragraphs (b)(1)(iii) and (b)(2)(ii) of this section.

(B) The use of Tier 4 is required.

(iii) Shall be used for a fuel not listed in Table C–1 of this subpart if the fuel is combusted in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr provided that both of the following conditions apply:

(A) The use of Tier 4 is not required.

(B) The fuel provides 10% or more of the annual heat input to the unit or, if § 98.36(c)(3) applies, to a group of units served by common supply pipe.

(4) The Tier 4 Calculation Methodology:

(i) May be used for a unit of any size, combusting any type of fuel.

(ii) Shall be used if the unit meets all six of the conditions specified in paragraphs (b)(4)(ii)(A) through (b)(4)(ii)(F) of this section:

(A) The unit has a maximum rated heat input capacity greater than 250 mmBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 250 tons per day of MSW.

(B) The unit combusts solid fossil fuel or MSW, either as a primary or secondary fuel.

(C) The unit has operated for more than 1,000 hours in any calendar year since 2005.

(D) The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit.

(E) The installed CEMS include a gas monitor of any kind or a stack gas volumetric flow rate monitor, or both and the monitors have been certified, either in accordance with the requirements of 40 CFR part 75, part 60 of this chapter, or an applicable State continuous monitoring program.

(F) The installed gas or stack gas volumetric flow rate monitors are required, either by an applicable Federal or State regulation or by the unit's operating permit, to undergo periodic quality assurance testing in accordance with either appendix B to 40 CFR part 75, appendix F to 40 CFR part 60, or an applicable State continuous monitoring program.

(iii) Shall be used for a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less and for a unit that combusts municipal solid waste with a maximum rated input capacity of 250 tons of MSW per day or less, if the unit meets all of the following three conditions:

(A) The unit has both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

(B) The unit meets the conditions specified in paragraphs (b)(4)(ii)(B) through (b)(4)(ii)(D) of this section.

(C) The CO_2 and stack gas volumetric flow rate monitors meet the conditions specified in paragraphs (b)(4)(ii)(E) and (b)(4)(ii)(F) of this section.

(5) The Tier 4 Calculation Methodology shall be used beginning on:

(i) January 1, 2010, for a unit that is required to report CO_2 mass emissions beginning on that date, if all of the monitors needed to measure CO_2 mass emissions have been installed and certified by that date.

(ii) January 1, 2011, for a unit that is required to report CO_2 mass emissions beginning on January 1, 2010, if all of the monitors needed to measure CO_2 mass emissions have not been installed and certified by January 1, 2010. In this case, you may use Tier 2 or Tier 3 to report GHG emissions for 2010.

(6) You may elect to use any applicable higher tier for one or more of the fuels combusted in a unit. For example, if a 100 mmBtu/hr unit combusts natural gas and distillate fuel oil, you may elect to use Tier 1 for natural gas and Tier 3 for the fuel oil, even though Tier 1 could have been used for both fuels. However, for units that use either the Tier 4 or the alternative calculation methodology specified in paragraph (a)(5) of this section, CO_2 emissions from the combustion of all fuels shall be based solely on CEMS measurements.

(c) *Calculation of CH_4 and N_2O emissions from stationary combustion sources.* You must calculate annual CH_4 and N_2O mass emissions only for units that are required to report CO_2 emissions using the calculation methodologies of this subpart and for only those fuels that are listed in Table C–2 of this subpart.

(1) Use Equation C–8 of this section to estimate CH_4 and N_2O emissions for any fuels for which you use the Tier 1 or Tier 3 calculation methodologies for CO_2. Use the same values for fuel combustion that you use for the Tier 1 or Tier 3 calculation.

$$CH_4 \ or \ N_2O = 1 \, x \, 10^{-3} * Fuel * HHV * EF \qquad \text{(Eq. C-8)}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted, either from company records or directly measured by a fuel flow meter, as applicable (mass or volume per year).

HHV = Default high heat value of the fuel from Table C–1 of this subpart (mmBtu per mass or volume).

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(2) Use Equation C–9a of this section to estimate CH_4 and N_2O emissions for any fuels for which you use the Tier 2 Equation C–2a of this section to estimate CO_2 emissions. Use the same values for fuel combustion and HHV that you use for the Tier 1 or Tier 3 calculation.

$$\mathrm{CH_4 \ or \ N_2O = 1 \, x \, 10^{-3} * HHV * EF * Fuel} \qquad \text{(Eq. C-9a)}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted during the reporting year.

HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (mmBtu per mass or volume).

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(3) Use Equation C–9b of this section to estimate CH_4 and N_2O emissions for any fuels for which you use Equation C–2c of this section to calculate the CO_2 emissions. Use the same values for steam generation and the ratio ''B'' that you use for Equation C–2c.

$$\mathrm{CH_4 \ or \ N_2O = 1 \, x \, 10^{-3} \ Steam * B * EF} \qquad \text{(Eq. C-9b)}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a solid fuel (metric tons).

Steam = Total mass of steam generated by solid fuel combustion during the reporting year (lb steam).

B = Ratio of the boiler's maximum rated heat input capacity to its design rated steam output (mmBtu/lb steam).

EF = Fuel-specific emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(4) Use Equation C–10 of this section for units in the Acid Rain Program, units that monitor and report heat input on a year-round basis according to 40 CFR part 75, and units that use the Tier 4 Calculation Methodology.

$$\mathrm{CH_4 \ or \ N_2O = 0.001 * (HI)_A * EF} \qquad \text{(Eq. C-10)}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).

$(HI)_A$ = Cumulative annual heat input from the fuel, derived from the electronic data reports required under § 75.64 of this chapter or, for Tier 4 units, from the best available information as described in paragraph (c)(4)(ii) of this section (mmBtu).

EF = Fuel-specific emission factor for CH_4 or N_2O, from Table C–2 of this section (kg CH_4 or N_2O per mmBtu).

0.001 = Conversion factor from kg to metric tons.

(i) If only one type of fuel listed in Table C–2 of this subpart is combusted during normal operation, substitute the cumulative annual heat input from combustion of the fuel into Equation C–10 of this section to calculate the annual CH_4 or N_2O emissions.

(ii) If more than one type of fuel listed in Table C–2 of this subpart is combusted during normal operation, use Equation C–10 of this section separately for each type of fuel. If flow rate and diluent gas monitors are used to measure the unit heat input, use the best available information (e.g., fuel feed rate measurements, fuel heating values, engineering analysis) to estimate the annual heat input from each type of fuel.

(5) When multiple fuels are combusted during the reporting year, sum the fuel-specific results from Equations C–8, C–9a, C–9b, or C–10 of this section (as applicable) to obtain the total annual CH_4 and N_2O emissions, in metric tons.

(d) Calculation of CO_2 from sorbent.

(1) When a unit is a fluidized bed boiler, is equipped with a wet flue gas desulfurization system, or uses other acid gas emission controls with sorbent injection, use Equation C–11 of this section to calculate the CO_2 emissions from the sorbent, if those CO_2 emissions are not monitored by CEMS:

$$CO_2 = 0.91 * S * R * \left(\frac{MW_{CO2}}{MW_S}\right) \qquad \text{(Eq. C-11)}$$

Where:

CO_2 = CO_2 emitted from sorbent for the reporting year (metric tons).
S = Limestone or other sorbent used in the reporting year, from company records (short tons).
R = 1.00, the calcium-to-sulfur stoichiometric ratio.
MW_{CO2} = Molecular weight of carbon dioxide (44).
MW_S = Molecular weight of sorbent (100 if calcium carbonate).
0.91 = Conversion factor from short tons to metric tons.

(2) The annual CO_2 mass emissions for the unit shall be the sum of the CO_2 emissions from the combustion process and the CO_2 emissions from the sorbent.

(e) *CO_2 emissions from combustion of biomass.* Use the procedures of this paragraph (e) to estimate biogenic CO_2 emissions from units that combust a combination of biomass and fossil fuels. Reporting of CO_2 emissions from combustion of biomass is required only for those biomass fuels listed in Table C–1 of this section, unless emissions are measured using CEMS.

(1) If CEMS are not used to measure CO_2, use Equation C–1 of this subpart to calculate the annual CO_2 mass emissions from the combustion of biomass (except MSW) for a unit of any size. Determine the mass of biomass combusted using one of the following procedures in this paragraph (e)(1), as appropriate.

(i) Use company records.

(ii) Follow the procedures in paragraph (e)(5) of this section.

(iii) For premixed fuels that contain biomass and fossil fuels (e.g., mixtures containing biodiesel), use best available information to determine the mass of biomass fuels and document the procedure used in the GHG Monitoring Plan required by § 98.3(g)(5).

(2) If a CO_2 CEMS (or a surrogate O_2 monitor) and a stack gas flow rate monitor are used to determine the annual CO_2 mass emissions either according to 40 CFR part 75, the Tier 4 Calculation Methodology, or the alternative calculation methodology specified in paragraph (a)(5)(iii); and if both fossil fuel and biomass (except for MSW) are combusted in the unit during the reporting year, you may use the following procedure to determine the annual biogenic CO_2 mass emissions. If MSW is combusted in the unit, follow the procedures in paragraph (e)(3) of this section.

(i) For each operating hour, use Equation C–12 of this section to determine the volume of CO_2 emitted.

$$V_{CO2h} = \frac{(\%CO_2)_h}{100} * Q_h * t_h \qquad \text{(Eq. C-12)}$$

Where:

V_{CO2h} = Hourly volume of CO_2 emitted (scf).
$(\%CO_2)_h$ = Hourly average CO_2 concentration, measured by the CO_2 concentration monitor, or, if applicable, calculated from the hourly average O_2 concentration ($\%CO_2$).
Q_h = Hourly average stack gas volumetric flow rate, measured by the stack gas volumetric flow rate monitor (scfh).
t_h = Source operating time (decimal fraction of the hour during which the source combusts fuel, i.e., 1.0 for a full operating hour, 0.5 for 30 minutes of operation, etc.).
100 = Conversion factor from percent to a decimal fraction.

(ii) Sum all of the hourly V_{CO2h} values for the reporting year, to obtain V_{total}, the total annual volume of CO_2 emitted.

(iii) Calculate the annual volume of CO_2 emitted from fossil fuel combustion using Equation C–13 of this section. If two or more types of fossil fuel are combusted during the year, perform a separate calculation with Equation C–13 of this section for each fuel and sum the results.

$$V_{ff} = \frac{\text{Fuel} * F_c * \text{HHV}}{10^6} \qquad \text{(Eq. C-13)}$$

Where:

V_{ff} = Annual volume of CO_2 emitted from combustion of a particular fossil fuel (scf).
Fuel = Total quantity of the fossil fuel combusted in the reporting year, from company records, as defined in § 98.6 (lb for solid fuel, gallons for liquid fuel, and scf for gaseous fuel).
F_c = Fuel-specific carbon based F-factor, either a default value from Table 1 in section 3.3.5 of appendix F to 40 CFR part 75 or a site-specific value determined under section 3.3.6 of appendix F to 40 CFR part 75 (scf CO_2/mmBtu).
HHV = High heat value of the fossil fuel, from fuel sampling and analysis (annual average value in Btu/lb for solid fuel, Btu/gal for liquid fuel and Btu/scf for gaseous fuel, sampled as specified (e.g., monthly, quarterly, semi-annually, or by lot) in § 98.34(a)(2)). The average HHV shall be calculated according to the requirements of paragraph (a)(2)(ii) of this section.
10^6 = Conversion factor, Btu per mmBtu.

(iv) Subtract V_{ff} from V_{total} to obtain V_{bio}, the annual volume of CO_2 from the combustion of biomass. If a CEMS is being used to measure the combined combustion and process emissions from a unit that is subject to another subpart of part 98, then also subtract CO_2 process emissions from V_{total} to determine V_{bio}. The CO_2 process emissions must be calculated according to the requirements of the applicable subpart.

(v) Calculate the biogenic percentage of the annual CO_2 emissions,expressed as a decimal fraction, using Equation C–14 of this section:

$$\%\ Biogenic = \frac{V_{bio}}{V_{total}} \qquad \text{(Eq. C-14)}$$

(vi) Calculate the annual biogenic CO_2 mass emissions, in metric tons, by multiplying the results obtained from Equation C–14 of this section by the annual CO_2 mass emissions in metric tons, as determined:

(A) Under paragraph (a)(4)(vi) of this section, for units using the Tier 4 Calculation Methodology.

(B) Under paragraph (a)(5)(iii)(B) of this section, for units using the alternative calculation methodology specified in paragraph (a)(5)(iii).

(C) From the electronic data report required under § 75.64 of this chapter, for units in the Acid Rain Program and other units using CEMS to monitor and report CO_2 mass emissions according to 40 CFR part 75. However, before calculating the annual biogenic CO_2 mass emissions, multiply the cumulative annual CO_2 mass emissions by 0.91 to convert from short tons to metric tons.

(3) For a unit that combusts MSW, the annual biogenic CO_2 emissions shall be calculated using the procedures in this paragraph (e)(3).

(i) If the Tier 1 or Tier 2 Calculation Methodology is used to quantify CO_2 mass emissions:

(A) Use Equation C–1 or C–2c of this subpart, as appropriate, to calculate the annual CO_2 mass emissions from MSW combustion.

(B) Determine the relative proportions of biogenic and non-biogenic CO_2 emissions on a quarterly basis using the method specified in § 98.34(d).

(C) Determine the annual biogenic CO_2 mass emissions from MSW combustion by multiplying the annual CO_2 mass emissions by the annual average biogenic decimal fraction obtained from § 98.34(d).

(ii) If the unit uses Tier 4 to quantify CO_2 emissions:

(A) Follow the procedures in paragraphs (e)(2)(i) and (ii) of this section, to determine V_{total}.

(B) If any fossil fuel was combusted during the year, follow the procedures in paragraph (e)(2)(iii) of this section, to determine V_{ff}.

(C) Subtract V_{ff} from V_{total}, to obtain V_{MSW}, the annual volume of CO_2 emissions from MSW combustion.

(D) Determine the annual volume of biogenic CO_2 emissions (V_{bio}) from MSW combustion as follows. Multiply the annual volume of CO_2 emissions from MSW combustion (V_{MSW}) by the annual average biogenic decimal fraction obtained from ASTM D6866–08 and ASTM D7459–08.

(E) Calculate the biogenic percentage of the annual CO_2 emissions from the unit, using Equation C–14 of this section. For the purposes of this calculation, the term ‘‘V_{bio}’’ in the numerator of Equation C–14 of this section shall be the results of the calculation performed under paragraph (e)(3)(ii)(D) of this section.

(F) Calculate the annual biogenic CO_2 mass emissions according to paragraph (e)(2)(vi)(A) of this section.

(4) As an alternative to the procedures in paragraph (e)(2) of this section, use ASTM Methods D7459–08 and D6866–08 to determine the biogenic portion of the annual CO_2 emissions, as described in § 98.34(e). If this option is selected, the results of each determination shall be expressed as a decimal fraction (e.g., 0.30, if 30 percent of the CO_2 is biogenic), and the values shall be averaged over the reporting year. The annual biogenic CO_2 mass emissions shall be calculated by multiplying the the total annual CO_2 mass emissions by the annual average biogenic fraction obtained from ASTM D6866–08 and ASTM D7459–08.

(5) If Equation C–1 of this section is selected to calculate the annual biogenic mass emissions for wood, wood waste, or other solid biomass-derived fuel, Equation C–15 of this section may be used to quantify biogenic fuel consumption, provided that all of the required input parameters are accurately quantified. Similar equations and calculation methodologies based on steam generation and boiler efficiency may be used, provided that they are documented in the GHG Monitoring Plan required by § 98.3(g)(5).

$$(Fuel)_p = \frac{[H * S] - (HI)_{nb}}{2000\,(HHV)_{bio}\,(Eff)_{bio}} \qquad \text{(Eq. C-15)}$$

Where:

$(Fuel)_p$ = Quantity of biomass consumed during the measurement period ‘‘p’’ (tons/year or tons/month, as applicable).

H = Average enthalpy of the boiler steam for the measurement period (Btu/lb).

S = Total boiler steam production for the measurement period (lb/month or lb/year, as applicable).

$(HI)_{nb}$ = Heat input from co-fired fossil fuels and non-biomass-derived fuels for the measurement period, based on company records of fuel usage and default or measured HHV values (Btu/month or Btu/year, as applicable).

$(HHV)_{bio}$ = Default or measured high heat value of the biomass fuel (Btu/lb).

$(Eff)_{bio}$ = Percent efficiency of biomass-to-energy conversion, expressed as a decimal fraction.

2000 = Conversion factor (lb/ton).

§ 98.34 Monitoring and QA/QC requirements.

The CO_2 mass emissions data for stationary fuel combustion sources shall be monitored as follows:

(a) For the Tier 2 Calculation Methodology:

(1) All fuel samples shall be taken at a location in the fuel handling system that provides a sample representative of the fuel combusted. The fuel sampling and analysis may be performed by either the owner or operator or the supplier of the fuel.

(2) The minimum required frequency of the HHV sampling and analysis for each type of fuel is specified in this paragraph. When the specified frequency is based on a specified time period (i.e., weekly, monthly, quarterly, or semiannually), fuel sampling and analysis is required only for those periods in which the unit operates.

(i) For natural gas, semiannual sampling and analysis is required (i.e., twice in a calendar year, with consecutive samples taken at least four months apart).

(ii) For coal and fuel oil, analysis of at least one representative sample from each fuel lot is required. For the purposes of this section, a fuel lot is defined as a shipment or delivery of a single fuel (e.g., ship load, barge load, group of trucks, group of railroad cars, etc.).

(iii) For liquid fuels other than fuel oil, for fossil fuel-derived gaseous fuels, and for biogas; sampling and analysis is required at least once per calendar quarter. To the extent practicable, consecutive quarterly samples shall be taken at least 30 days apart.

(iv) For solid fuels other than coal and MSW, weekly sampling is required to obtain composite samples, which are then analyzed monthly.

(3) If different types of fuel (e.g., different ranks of coal or different grades of fuel oil) are blended prior to combustion, use one of the following procedures in this paragraph.

(i) Use a weighted HHV value in the emission calculations, based on the relative proportions of each fuel in the blend.

(ii) Take a representative sample of the blend and analyze it for HHV.

(4) If, for a particular type of fuel, HHV sampling and analysis is performed more often than the minimum frequency specified in paragraph (a)(2) of this section, the results of all valid fuel analyses shall be used in the GHG emission calculations.

(5) If, for a particular type of fuel, valid HHV values are obtained at less than the minimum frequency specifed in paragraph (a)(2) of this section, appropriate substitute data values shall be used in the emissions calculations, in accordance with missing data procedures of § 98.35.

(6) Use any applicable fuel sampling and analysis methods in this paragraph (a)(6) to determine the high heat values. Alternatively, for gaseous fuels, the HHV may be calculated using chromatographic analysis together with standard heating values of the fuel constituents, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions.

(i) ASTM D4809–06 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) (incorporated by reference, see § 98.7).

(ii) ASTM D240–02 (Reapproved 2007) Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (incorporated by reference, see § 98.7).

(iii) ASTM D1826–94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter (incorporated by reference, *see* § 98.7).

(iv) ASTM D3588–98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (incorporated by reference, *see* § 98.7).

(v) ASTM D4891–89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (incorporated by reference, *see* § 98.7).

(vi) GPA Standard 2172–09 Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer (incorporated by reference, *see* § 98.7).

(vii) GPA Standard 2261–00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, *see* § 98.7).

(viii) ASTM D5865–07a, Standard Test Method for Gross Calorific Value of Coal and Coke (incorporated by reference, *see* § 98.7).

(b) For the Tier 3 Calculation Methodology:

(1) Calibrate each oil and gas flow meter according to § 98.3(i) and the provisions of this paragraph (b).

(i) Perform calibrations using any of the test methods and procedures in this paragraph (b)(1)(i):

(A) An applicable flow meter test method listed in paragraphs (b)(4)(i) through (b)(4)(viii) of this section.

(B) The calibration procedures specified by the flow meter manufacturer.

(C) An industry-accepted or industry standard calibration practice.

(ii) In addition to the initial calibration required by § 98.3(i), recalibrate each fuel flow meter (except for qualifying billing meters under paragraph (b)(1)(iii) of this section) either annually, at the minimum frequency specified by the manufacturer, or at the interval specified by the industry consensus standard practice used.

(iii) Fuel billing meters are exempted from the initial and ongoing calibration requirements of this paragraph, provided that the fuel supplier and the unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company.

(iv) For the initial calibration of an orifice, nozzle, or venturi meter; in-situ calibration of the transmitters is sufficient. A primary element inspection (PEI) shall be performed at least once every three years.

(v) For the continuously-operating units and processes described in § 98.3(i)(6), the required flow meter recalibrations and, if necessary, the PEIs may be postponed until the next scheduled maintenance outage.

(vi) If a mixture of fuels is transported by a common pipe (e.g., still gas and supplementary natural gas), you must either separately meter each of the fuels prior to mixing using flow meters calibrated according to § 98.3(i), or use flow meters calibrated according to § 98.3(i) to measure the mixed fuel at the common pipe and to separately meter an appropriate subset of the fuels prior to mixing. If the latter option is chosen, quantify the fuels that are not measured prior to mixing by subtracting out the fuels measured prior to mixing from the fuel measured at the common pipe.

(2) Oil tank drop measurements (if used to determine liquid fuel use volume) shall be performed according to any an appropriate method published by a consensus-based standards organization (e.g., the American Petroleum Institute).

(3) The carbon content and, if applicable, molecular weight of the fuels shall be determined according to the procedures in this paragraph (b)(3).

(i) All fuel samples shall be taken at a location in the fuel handling system that provides a sample representative of the fuel combusted. The fuel sampling and analysis may be performed by either the owner or operator or by the supplier of the fuel.

(ii) At a minimum, fuel samples shall be collected at the frequency specified in this paragraph. When sampling is required at a specified time interval (e.g., weekly, monthly, quarterly, or semiannually), fuel sampling and analysis is required for only those specified periods in which the unit operates.

(A) For natural gas, semiannual sampling and analysis is required (i.e., twice in a calendar year, with consecutive samples taken at least four months apart).

(B) For coal and fuel oil, analysis of at least one representative sample from each fuel lot is required. For the purposes of this section, a fuel lot is defined as a shipment or delivery of a single fuel (e.g., ship load, barge load, group of trucks, group of railroad cars, etc.).

(C) For other liquid fuels other than fuel oil, for fossil fuel-derived gaseous fuels, and for biogas; sampling and analysis is required at least once per calendar quarter. To the extent practicable, consecutive quarterly samples shall be taken at least 30 days apart.

(D) For solid fuels other than coal, weekly sampling is required to obtain composite samples, which are then analyzed monthly.

(E) For gaseous fuels other than natural gas and biogas (e.g., refinery gas), daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if the necessary equipment is in place to make these measurements. Otherwise, weekly sampling and analysis shall be performed.

(iii) If, for a particular type of fuel, sampling and analysis for carbon content and molecular weight is performed more often than the minimum frequency specified in paragraph (b)(3) of this section, the results of all valid fuel analyses shall be used in the GHG emission calculations.

(iv) If, for a particular type of fuel, sampling and analysis for carbon content and molecular weight is performed at less than the minimum frequency specified in paragraph (b)(3) of this section, appropriate substitute data values shall be used in the emissions calculations, in accordance with the missing data procedures of § 98.35.

(v) The procedures of paragraph (a)(3) of this section apply to carbon content and molecular weight determinations.

(4) Use any applicable standard method from the following list to quality assure the data from each fuel flow meter.

(i) AGA Report No. 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines (1990) and Part 2: Specification and Installation Requirements (2000) (incorporated by reference, *see* § 98.7).

(ii) AGA Transmission Measurement Committee Report No. 7, Measurement of Gas by Turbine Meters (2006) (incorporated by reference, *see* § 98.7).

(iii) ASME MFC–3M–2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, *see* § 98.7).

(iv) ASME MFC–4M–1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters (incorporated by reference, *see* § 98.7).

(v) ASME MFC–5M–1985 (Reaffirmed 1994), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters (incorporated by reference, *see* § 98.7).

(vi) ASME MFC–6M–1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, *see* § 98.7).

(vii) ASME MFC–7M–1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, *see* § 98.7).

(viii) ASME MFC–9M–1988 (Reaffirmed 2001), Measurement of Liquid Flow in Closed Conduits by Weighing Method (incorporated by reference, *see* § 98.7).

(5) Use any applicable methods from the following list to determine the carbon content and molecular weight (for gaseous fuel) of the fuel. Alternatively, the results of chromatographic analysis of the fuel may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions.

(i) ASTM D1945–03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, *see* § 98.7).

(ii) ASTM D1946–90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, *see* § 98.7).

(iii) ASTM D2502–04 (Reapproved 2002) Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements (incorporated by reference, *see* § 98.7).

(iv) ASTM D2503–92 (Reapproved 2007) Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure (incorporated by reference, *see* § 98.7).

(v) ASTM D3238–95 (Reapproved 2005) Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method (incorporated by reference, *see* § 98.7).

(vi) ASTM D5291–02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, *see* § 98.7).

(vii) ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, *see* § 98.7).

(c) For the Tier 4 Calculation Methodology, the CO_2 and flow rate monitors must be certified prior to the applicable deadline specified in § 98.33(b)(5).

(1) For initial certification, you may use any one of the following three procedures in this paragraph.

(i) § 75.20(c)(2) and (4) and appendix A to 40 CFR part 75.

(ii) The calibration drift test and relative accuracy test audit (RATA) procedures of Performance Specification 3 in appendix B to part 60 (for the CO_2 concentration monitor) and Performance Specification 6 in appendix B to part 60 (for the continuous emission rate monitoring system (CERMS)).

(iii) The provisions of an applicable State continuous monitoring program.

(2) If an O_2 concentration monitor is used to determine CO_2 concentrations, the applicable provisions of 40 CFR part 75, 40 CFR part 60, or an applicable State continuous monitoring program shall be followed for initial certification and on-going quality assurance, and all required RATAs of the monitor shall be done on a percent CO_2 basis.

(3) For ongoing quality assurance, follow the applicable procedures in either appendix B to 40 CFR part 75, appendix F to 40 CFR part 60, or an applicable State continuous monitoring program. If appendix F to 40 CFR part 60 is selected for on-going quality assurance, perform daily calibration drift assessments for both the CO_2 monitor (or surrogate O_2 monitor) and the flow rate monitor, conduct cylinder gas audits of the CO_2 concentration monitor in three of the four quarters of each year (except for non-operating quarters), and perform annual RATAs of the CO_2 concentration monitor and the CERMS.

(4) For the purposes of this part, the stack gas volumetric flow rate monitor RATAs required by appendix B to 40 CFR part 75 and the annual RATAs of the CERMS required by appendix F to 40 CFR part 60 need only be done at one operating level, representing normal load or normal process operating conditions, both for initial certification and for ongoing quality assurance.

(5) If, for any source operating hour, quality assured data are not obtained with a CO_2 monitor (or surrogate O_2 monitor), flow rate monitor, or (if applicable) moisture monitor, use appropriate substitute data values in accordance with the missing data provisions of § 98.35.

(d) When municipal solid waste (MSW) is combusted in a unit, determine the biogenic portion of the CO_2 emissions from MSW combustion using ASTM D6866–08 Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis (incorporated by reference, *see* § 98.7) and ASTM D7459–08 Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources (incorporated by reference, *see* § 98.7). Perform the ASTM D7459–08 sampling and the ASTM D6866–08 analysis at least once in every calendar quarter in which MSW is combusted in the unit. Collect each gas sample during normal unit operating conditions while MSW is the only fuel being combusted for at least 24 consecutive hours or for as long as is necessary to obtain a sample large enough to meet the specifications of ASTM D6866–08. Separate CO_2 emissions into the biogenic and non-biogenic fraction using the average proportion of biogenic emissions of all samples analyzed during the reporting year. Express the results as a decimal fraction (e.g., 0.30, if 30 percent of the CO_2 from MSW combustion is biogenic). If there is a common fuel source of MSW that feeds multiple units at the facility, performing the testing at only one of the units is sufficient.

(e) For units that use CEMS to measure the total CO_2 mass emissions and combust a combination of biogenic fuels (other than MSW) with a fossil fuel, ASTM D6866–08 and ASTM D7459–08 may be used to determine the biogenic portion of the CO_2 emissions. Perform the ASTM D7459–08 sampling and the ASTM D6866–08 analysis at least once in every calendar quarter in which biogenic and non-biogenic fuels are co-fired in the unit. The relative proportions of the biogenic and non-biogenic fuels during the sampling shall be representative of the average fuel blend for a typical operating year. Collect each gas sample using ASTM D7459–08 during normal unit operation for at least 24 consecutive hours or for as long as is necessary to obtain a sample large enough to meet the specifications of ASTM D6866–08.

(f) Whenever company records are used in the calculation of CO_2 emissions, the records required under § 98.3(g) shall include both the company records and an explanation of how those records are used to estimate the following parameters:

(1) Fuel consumption, when the Tier 1 and Tier 2 Calculation Methodologies are used.

(2) Fuel consumption, when solid fuel is combusted and the Tier 3 Calculation Methodology is used.

(3) Fossil fuel consumption when § 98.33(e) applies to a unit that uses CEMS to quantify CO_2 emissions and that combusts both fossil and biomass fuels.

(4) Sorbent usage, when § 98.33(d) applies.

(5) Quantity of steam generated by a unit when § 98.33(a)(2) applies.

(6) Biogenic fuel consumption under § 98.33(e)(5).

(g) As part of the GHG Monitoring Plan required under § 98.3(g)(5), you must document the procedures used to ensure the accuracy of the estimates of fuel usage, sorbent usage, steam production, and boiler efficiency (as applicable) in paragraph (f) of this section, including but not limited to calibration of weighing equipment, fuel flow meters, steam flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

§ 98.35 Procedures for estimating missing data.

Whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For all units subject to the requirements of the Acid Rain Program, and all other stationary combustion units subject to the requirements of this part that monitor and report emissions and heat input data in accordance with 40 CFR part 75, the missing data substitution procedures in 40 CFR part 75 shall be followed for CO_2 concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

(b) For units that use the Tier 1, Tier 2, Tier 3, and Tier 4 Calculation Methodologies, perform missing data substitution as follows for each parameter:

(1) For each missing value of the high heating value, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the ''after'' value has not been obtained by the time that the GHG emissions report is due, you may use the ''before'' value for missing data substitution or the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours). If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(2) For missing records of CO_2 concentration, stack gas flow rate, percent moisture, fuel usage, and sorbent usage, the substitute data value shall be the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours, etc.). You must document and retain records of the procedures used for all such estimates.

§ 98.36 Data reporting requirements.

(a) In addition to the facility-level information required under § 98.3, the annual GHG emissions report shall contain the unit-level or process-level emissions data in paragraphs (b) through (d) of this section (as applicable) and the emissions verification data in paragraph (e) of this section.

(b) *Units that use the four tiers.* You shall report the following information for stationary combustion units that use the Tier 1, Tier 2, Tier 3, or Tier 4 methodology in § 98.33(a) to calculate CO_2 emissions, except as otherwise provided in paragraphs (c) and (d) of this section:

(1) The unit ID number.

(2) A code representing the type of unit.

(3) Maximum rated heat input capacity of the unit, in mmBtu/hr for boilers and process heaters only and relevant units of measure for other combustion sources.

(4) Each type of fuel combusted in the unit during the report year.

(5) The tier used to calculate the CO_2 emissions for each type of fuel combusted (i.e., Tier 1, 2, 3, or 4).

(6) For a unit that uses Tiers 1, 2, and 3; the CO_2, CH_4, and N_2O emissions for each type of fuel combusted, expressed in metric tons of each gas and in metric tons of CO_2e.

(7) For a unit that uses Tier 4:

(i) For units that burn fossil fuels only, the annual CO_2 emissions for all fuels combined. Reporting CO_2 emissions by type of fuel is not required.

(ii) For units that burn both fossil fuels and biomass, the annual CO_2 emissions from combustion of all fossil fuels combined and the annual CO_2 emissions from combustion of all biomass fuels combined. Reporting CO_2 emissions by type of fuel is not required.

(iii) Annual CH_4 and N_2O emissions for each type of fuel combusted expressed in metric tons of each gas and in metric tons of CO_2e.

(8) Annual CO_2 emissions from sorbent (if calculated using Equation C–11 of this subpart), expressed in metric tons.

(9) Annual GHG emissions from all fossil fuels burned in the unit (i.e., the sum of the CO_2, CH_4, and N_2O emissions), expressed in metric tons of CO_2e.

(10) Customer meter number for units that combust natural gas.

(c) *Reporting alternatives for units using the four Tiers.* You may use any of the applicable reporting alternatives of this paragraph to simplify the unit-level reporting required under paragraph (b) of this section:

(1) *Aggregation of units.* If a facility contains two or more units (e.g., boilers or combustion turbines), each of which has a maximum rated heat input capacity of 250 mmBtu/hr or less, you may report the combined GHG emissions for the group of units in lieu of reporting GHG emissions from the individual units, provided that the use of Tier 4 is not required or elected for

any of the units and the units use the same tier for any common fuels combusted. If this option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

(i) Group ID number, beginning with the prefix ''GP''.

(ii) An identification number for each unit in the group.

(iii) Cumulative maximum rated heat input capacity of the group (mmBtu/hr).

(iv) The highest maximum rated heat input capacity of any unit in the group (mmBtu/hr).

(v) Each type of fuel combusted in the group of units during the reporting year.

(vi) Annual CO_2, CH_4, and N_2O mass emissions aggregated for each type of fuel combusted in the group of units during the year, expressed in metric tons of each gas and in metric tons of CO_2e. If any of the units burn both fossil fuels and biomass, report also the annual CO_2 emissions from combustion of all fossil fuels combined and annual CO_2 emissions from combustion of all biomass fuels combined, expressed in metric tons.

(vii) The tier used to calculate the CO_2 mass emissions for each type of fuel combusted in the units (i.e., Tier 1, Tier 2, or Tier 3).

(viii) The calculated CO_2 mass emissions (if any) from sorbent.

(ix) Annual GHG emissions from all fossil fuels burned in the group (i.e., the sum of the CO_2, CH_4, and N_2O emissions), expressed in metric tons of CO_2e.

(2) *Monitored common stack or duct configurations*. When the flue gases from two or more stationary combustion units at a facility are discharged through a common stack or duct before exiting to the atmosphere and if CEMS are used to continuously monitor CO_2 mass emissions at the common stack or duct according to the Tier 4 Calculation Methodology, you may report the combined emissions from the units sharing the common stack or duct, in lieu of separately reporting the GHG emissions from the individual units. The following information shall be reported instead of the information in paragraph (b) of this section:

(i) Common stack or duct identification number, beginning with the prefix ''CS''.

(ii) Identification numbers of the units sharing the common stack or duct.

(iii) Maximum rated heat input capacity of each unit sharing the common stack or duct (mmBtu/hr).

(iv) Each type of fuel combusted in the units during the year.

(v) The methodology used to calculate the CO_2 mass emissions, i.e., Tier 4.

(vi) If the any of the units burn both fossil fuels and biomass, annual CO_2 mass emissions, annual CO_2 emissions from combustion of fossil fuels, and annual CO_2 emissions from combustion of biomass measured at the common stack or duct, expressed in metric tons.

(vii) The annual CH_4 and N_2O emissions from the units sharing the common stack or duct, expressed in metric tons of each gas and in metric tons of CO_2e.

(viii) Annual GHG emissions from all fossil fuels burned in the group (i.e., the sum of the CO_2, CH_4, and N_2O emissions), expressed in metric tons of CO_2e.

(3) *Common pipe configurations*. When two or more liquid-fired or gaseous-fired stationary combustion units at a facility combust the same type of fuel and the fuel is fed to the individual units through a common supply line or pipe, you may report the combined emissions from the units served by the common supply line, in lieu of separately reporting the GHG emissions from the individual units, provided that the total amount of fuel combusted by the units is accurately measured at the common pipe or supply line using a fuel flow meter that is calibrated in accordance with § 98.34(a). If a portion of the fuel measured at the common pipe is diverted to a chemical or industrial process where it is used but not combusted, you may subtract the diverted fuel from the fuel measured at the common pipe prior to performing the GHG emissions calculations, provided that the amount of fuel diverted is also measured with a calibrated flow meter per § 98.3(i). If the common pipe option is selected, the applicable tier shall be used based on the maximum rated heat input capacity of the largest unit served by the common pipe configuration. The following information shall be reported instead of the information in paragraph (b) of this section:

(i) Common pipe identification number, beginning with the prefix ''CP''.

(ii) The identification numbers of the units served by the common pipe.

(iii) Maximum rated heat input capacity of each unit served by the common pipe (mmBtu/hr).

(iv) The fuels combusted in the units during the reporting year.

(v) The methodology used to calculate the CO_2 mass emissions (i.e., Tier 1, Tier 2, or Tier 3).

(vi) If the any of the units burns both fossil fuels and biomass, the annual CO_2 mass emissions from combustion of all fossil fuels and annual CO_2 emissions from combustion of all biomass fuels from the units served by the common pipe, expressed in metric tons.

(vii) Annual CH_4 and N_2O emissions from the units served by the common pipe, expressed in metric tons of each gas and in metric tons of CO_2e.

(viii) Annual GHG emissions from all fossil fuels burned in units served by the common pipe (i.e., the sum of the CO_2, CH_4, and N_2O emissions), expressed in metric tons of CO_2e.

(d) Units subject to 40 CFR part 75.

(1) For stationary combustion units that are either subject to the Acid Rain Program or not in the Acid Rain Program but monitor and report CO_2 mass emissions year-round according to 40 CFR part 75, you shall report the following unit-level information:

(i) Unit or stack identification numbers. Use exact same unit, common stack, or multiple stack identification numbers that represent the monitored locations (e.g., 1, 2, CS001, MS1A, etc.) that are reported under § 75.64 of this chapter.

(ii) Annual CO_2, CH_4, and N_2O emissions at each monitored location, expressed in metric tons of CO_2e.

(iii) Identification of the Part 75 methodology used to determine the CO_2 mass emissions.

(2) For units that use the alternative CO_2 mass emissions calculation methods for units with continuous monitoring systems provided in § 98.33(a)(5), you shall report the following unit-level information:

(i) Unit, stack, or pipe ID numbers. Use exact same unit, common stack, or multiple stack identification numbers that represent the monitored locations (e.g., 1, 2, CS001, MS1A, etc.) that are reported under § 75.64 of this chapter.

(ii) For units that use the alternative methods specified in § 98.33(a)(5)(i) and (ii) to monitor and report heat input data year-round according to appendix D to 40 CFR part 75 or 40 CFR 75.19:

(A) Each type of fuel combusted in the unit during the reporting year.

(B) The methodology used to calculate the CO_2 mass emissions for each fuel type.

(C) A code or flag to indicate whether heat input is calculated according to appendix D to 40 CFR part 75 or 40 CFR 75.19.

(D) Annual CO_2, CH_4, and N_2O emissions at each monitored location, across all fuel types, expressed in metric tons of CO_2e.

(iii) For units with continuous monitoring systems that use the alternative method for units with continuous monitoring systems in § 98.33(a)(5)(iii) to monitor heat input year-round according to 40 CFR part 75:

(A) Fuel combusted during the reporting year.

(B) Methodology used to calculate the CO_2 mass emissions.

(C) A code or flag to indicate that the heat input data is derived from CEMS measurements.

(D) The total annual CO_2, CH_4, and N_2O emissions at each monitored location, expressed in metric tons of CO_2e.

(e) *Verification data.* You must keep on file, in a format suitable for inspection and auditing, sufficient data to verify the reported GHG emissions. This data and information must, where indicated in this paragraph (e), be included in the annual GHG emissions report.

(1) The applicable verification data specified in this paragraph (e) are not required to be kept on file or reported for units that meet any one of the three following conditions:

(i) Are subject to the Acid Rain Program.

(ii) Use the alternative methods for units with continuous monitoring systems provided in § 98.33(a)(5).

(iii) Are not in the Acid Rain Program, but are required monitor and report CO_2 mass emissions and heat input data year-round, in accordance with 40 CFR part 75.

(2) For stationary combustion sources using the Tier 1, Tier 2, Tier 3, and Tier 4 Calculation Methodologies in § 98.33(a) to quantify CO_2 emissions, the following additional information shall be kept on file and included in the GHG emissions report, where indicated:

(i) For the Tier 1 Calculation Methodology, report the total quantity of each type of fuel combusted in the unit or group of aggregated units (as applicable) during the reporting year, in short tons for solid fuels, gallons for liquid fuels and standard cubic feet for gaseous fuels.

(ii) For the Tier 2 Calculation Methodology, report:

(A) The total quantity of each type of fuel combusted in the unit or group of aggregated units (as applicable) during each month of the reporting year. Express the quantity of each fuel combusted during the measurement period in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

(B) The frequency of the HHV determinations (e.g., once a month, once per fuel lot).

(C) The high heat values used in the CO_2 emissions calculations for each type of fuel combusted, in mmBtu per short ton for solid fuels, mmBtu per gallon for liquid fuels, and mmBtu per scf for gaseous fuels. Specify the date on which each fuel sample was taken. Indicate whether each HHV is a measured value of a substitute data value.

(D) If Equation C–2c of this subpart is used to calculate CO_2 mass emissions, report the total quantity (i.e., pounds) of steam produced from MSW or solid fuel combustion during the year, and the ratio of the maximum rate heat input capacity to the design rated steam output capacity of the unit, in mmBtu per lb of steam.

(iii) For the Tier 2 Calculation Methodology, keep records of the methods used to determine the HHV for each type of fuel combusted and the date on which each fuel sample was taken.

(iv) For the Tier 3 Calculation Methodology, report:

(A) The quantity of each type of fuel combusted in the unit or group of units (as applicable) during the year, in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

(B) The frequency of carbon content and, if applicable, molecular weight determinations for each type of fuel for the reporting year (e.g., daily, weekly, monthly, semiannually, once per fuel lot).

(C) The carbon content and, if applicable, gas molecular weight values used in the emission calculations (including both valid and substitute data values). Report all measured values if the fuel is sampled monthly or less frequently. Otherwise, for daily and weekly sampling, report monthly average values determined using the calculation procedures in Equation C–2b for each variable. Express carbon content as a decimal fraction for solid fuels, kg C per gallon for liquid fuels, and kg C per kg of fuel for gaseous fuels. Express the gas molecular weights in units of kg per kg-mole.

(D) The total number of valid carbon content determinations and, if applicable, molecular weight determinations made during the reporting year, for each fuel type.

(E) The number of substitute data values used for carbon content and, if applicable, molecular weight used in the annual GHG emissions calculations.

(v) For the Tier 3 Calculation Methodology, keep records of the following:

(A) For liquid and gaseous fuel combustion, the dates and results of the initial calibrations and periodic recalibrations of the required fuel flow meters.

(B) For fuel oil combustion, the method from § 98.34(b) used to make tank drop measurements (if applicable).

(C) The methods used to determine the carbon content for each type of fuel combusted.

(D) The methods used to calibrate the fuel flow meters).

(vi) For the Tier 4 Calculation Methodology, report:

(A) The total number of source operating hours in the reporting year.

(B) The cumulative CO_2 mass emissions in each quarter of the reporting year, i.e., the sum of the hourly values calculated from Equation C–6 or C–7 of this subpart (as applicable), in metric tons.

(C) For CO_2 concentration, stack gas flow rate, and (if applicable) stack gas moisture content, the percentage of source operating hours in which a substitute data value of each parameter was used in the emissions calculations.

(vii) For the Tier 4 Calculation Methodology, keep records of:

(A) Whether the CEMS certification and quality assurance procedures of 40 CFR part 75, 40 CFR part 60, or an applicable State continuous monitoring program were used.

(B) The dates and results of the initial certification tests of the CEMS.

(C) The dates and results of the major quality assurance tests performed on the CEMS during the reporting year, i.e., linearity checks, cylinder gas audits, and relative accuracy test audits (RATAs).

(viii) If CO_2 emissions that are generated from acid gas scrubbing with sorbent injection are not captured using CEMS, report:

(A) The total amount of sorbent used during the report year, in short tons.

(B) The molecular weight of the sorbent.

(C) The ratio (''R'') in Equation C–11 of this subpart.

(ix) For units that combust both fossil fuel and biomass, when CEMS are used to quantify the annual CO_2 emissions and biogenic CO_2 is determined according to § 98.33(e)(2), you shall report the following additional information, as applicable:

(A) The annual volume of CO_2 emitted from the combustion of all fuels, i.e., V_{total}, in scf.

(B) The annual volume of CO_2 emitted from the combustion of fossil fuels, i.e., V_{ff}, in scf. If more than one type of fossil fuel was combusted, report the combustion volume of CO_2 for each fuel separately as well as the total.

(C) The annual volume of CO_2 emitted from the combustion of biomass, i.e., V_{bio}, in scf.

(D) The carbon-based F-factor used in Equation C–13 of this subpart, for each type of fossil fuel combusted, in scf CO_2 per mmBtu.

(E) The annual average HHV value used in Equation C–13 of this subpart, for each type of fossil fuel combusted, in Btu/lb, Btu/gal, or Btu/scf, as appropriate.

(F) The total quantity of each type of fossil fuel combusted during the reporting year, in lb, gallons, or scf, as appropriate.

(G) Annual biogenic CO_2 mass emissions, in metric tons.

(x) When ASTM methods D7459–08 and D6866–08 are used to determine the biogenic portion of the annual CO_2 emissions from MSW combustion, report:

(A) The results of each quarterly sample analysis, expressed as a decimal fraction (e.g., if the biogenic fraction of the CO_2 emissions from MSW combustion is 30 percent, report 0.30).

(B) Annual combined biomass and fossil fuel CO_2 emissions from MSW combustion, in metric tons of CO_2e.

(C) The quantities V_{ff}, V_{total}, and V_{MSW} from § 98.33(e)(4)(ii), if CEMS are used to measure CO_2 emissions.

(D) The annual volume of biogenic CO_2 emissions from MSW combustion, in metric tons.

(xi) When ASTM methods D7459–08 and D6866–08 are used to determine the biogenic portion of the annual CO_2 emissions from a unit that co-fires biogenic (other than MSW) and non-biogenic fuels, you shall report the results of each quarterly sample analysis, expressed as a decimal fraction (e.g., if the biogenic fraction of the CO_2 emissions is 30 percent, report 0.30).

(3) Within 30 days of receipt of a written request from the Administrator, you shall submit explanations of the following:

(i) An explanation of how company records are used to quantify fuel consumption, if the Tier 1 or Tier 2 Calculation Methodology is used to calculate CO_2 emissions.

(ii) An explanation of how company records are used to quantify fuel consumption, if solid fuel is combusted and the Tier 3 Calculation Methodology is used to calculate CO_2 emissions.

(iii) An explanation of how sorbent usage is quantified.

(iv) An explanation of how company records are used to quantify fossil fuel consumption in units that uses CEMS to quantify CO_2 emissions and combusts both fossil fuel and biomass.

(v) An explanation of how company records are used to measure steam production, when it is used to calculate CO_2 mass emissions under § 98.33(a)(2)(iii) or to quantify solid fuel usage under § 98.33(c)(3).

(4) Within 30 days of receipt of a written request from the Administrator, you shall submit the verification data and information described in paragraphs (e)(2)(iii), (e)(2)(v), and (e)(2)(vii) of this section.

§ 98.37 Records that must be retained.

In addition to the requirements of § 98.3(g), you must retain the applicable records specified in §§ 98.34(f) and (g), 98.35(b), and 98.36(e).

§ 98.38 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE C–1 TO SUBPART C OF PART 98—DEFAULT CO_2 EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL

Fuel type	Default high heat value	Default CO_2 emission factor
Coal and coke	mmBtu/short ton	kg CO_2/mmBtu
Anthracite	25.09	103.54
Bituminous	24.93	93.40
Subbituminous	17.25	97.02
Lignite	14.21	96.36
Coke	24.80	102.04
Mixed (Commercial sector)	21.39	95.26
Mixed (Industrial coking)	26.28	93.65
Mixed (Industrial sector)	22.35	93.91
Mixed (Electric Power sector)	19.73	94.38
Natural gas	mmBtu/scf	kg CO_2/mmBtu
Pipeline (Weighted U.S. Average)	1.028×10^{-3}	53.02
Petroleum products	mmBtu/gallon	kg CO_2/mmBtu
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Residual Fuel Oil No. 5	0.140	72.93
Residual Fuel Oil No. 6	0.150	75.10
Still Gas	0.143	66.72
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.096	62.64
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15
Butylene	0.103	67.73
Naphtha (<401 deg F)	0.125	68.02
Natural Gasoline	0.110	66.83
Other Oil (>401 deg F)	0.139	76.22
Pentanes Plus	0.110	70.02
Petrochemical Feedstocks	0.129	70.97

TABLE C–1 TO SUBPART C OF PART 98—DEFAULT CO_2 EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL—Continued

Fuel type	Default high heat value	Default CO_2 emission factor
Petroleum Coke	0.143	102.41
Special Naphtha	0.125	72.34
Unfinished Oils	0.139	74.49
Heavy Gas Oils	0.148	74.92
Lubricants	0.144	74.27
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22
Asphalt and Road Oil	0.158	75.36
Crude Oil	0.138	74.49
Fossil fuel-derived fuels (solid)	mmBtu/short ton	kg CO_2/mmBtu
Municipal Solid Waste [1]	9.95	90.7
Tires	26.87	85.97
Fossil fuel-derived fuels (gaseous)	mmBtu/scf	kg CO_2/mmBtu
Blast Furnace Gas	0.092×10^{-3}	274.32
Coke Oven Gas	0.599×10^{-3}	46.85
Biomass fuels—solid	mmBtu/short ton	kg CO_2/mmBtu
Wood and Wood Residuals	15.38	93.80
Agricultural Byproducts	8.25	118.17
Peat	8.00	111.84
Solid Byproducts	25.83	105.51
Biomass fuels—gaseous	mmBtu/scf	kg CO_2/mmBtu
Biogas (Captured methane)	0.841×10^{-3}	52.07
Biomass Fuels—Liquid	mmBtu/gallon	kg CO_2/mmBtu
Ethanol (100%)	0.084	68.44
Biodiesel (100%)	0.128	73.84
Rendered Animal Fat	0.125	71.06
Vegetable Oil	0.120	81.55

[1] Allowed only for units that do not generate steam and use Tier 1.

TABLE C–2 TO SUBPART C OF PART 98—DEFAULT CH_4 AND N_2O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL

Fuel type	Default CH_4 emission factor (kg CH_4/mmBtu)	Default N_2O emission factor (kg N_2O/mmBtu)
Coal and Coke (All fuel types in Table C–1)	1.1×10^{-2}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}
Petroleum (All fuel types in Table C–1)	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels—Solid (All fuel types in Table C–1)	3.2×10^{-02}	4.2×10^{-03}
Biogas	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels—Liquid (All fuel types in Table C–1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1g of CH_4/MMBtu.

[1] Allowed only for units that do not generate steam and use Tier 1.

TABLE C–2 TO SUBPART C—DEFAULT CH_4 AND N_2O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL

Fuel type	Default CH_4 emission factor (kg CH_4/mmBtu)	Default N_2O emission factor (kg N_2O/mmBtu)
Coal and Coke (All fuel types in Table C–1)	1.1×10^{-2}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}

TABLE C–2 TO SUBPART C—DEFAULT CH_4 AND N_2O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL—Continued

Fuel type	Default CH_4 emission factor (kg CH_4/mmBtu)	Default N_2O emission factor (kg N_2O/mmBtu)
Petroleum (All fuel types in Table C–1)	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels—Solid (All fuel types in Table C–1)	3.2×10^{-02}	4.2×10^{-03}
Biogas	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels—Liquid (All fuel types in Table C–1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the ‘‘Energy Industry’’ or ‘‘Manufacturing Industries and Construction’’. In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC ‘‘Energy Industry’’ category may employ a value of 1 g of CH_4/MMBtu.

Subpart D—Electricity Generation

§ 98.40 Definition of the source category.

(a) The electricity generation source category comprises electricity generating units that are subject to the requirements of the Acid Rain Program and any other electricity generating units that are required to monitor and report to EPA CO_2 emissions year-round according to 40 CFR part 75.

(b) This source category does not include portable equipment, emergency equipment, or emergency generators, as defined in § 98.6.

§ 98.41 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains one or more electricity generating units and the facility meets the requirements of § 98.2(a)(1).

§ 98.42 GHGs to report.

(a) For each electricity generating unit that is subject to the requirements of the Acid Rain Program or is otherwise required to monitor and report to EPA CO_2 emissions year-round according to 40 CFR part 75, you must report under this subpart the annual mass emissions of CO_2, N_2O, and CH_4 by following the requirements of this subpart.

(b) For each electricity generating unit that is not subject to the Acid Rain Program or otherwise required to monitor and report to EPA CO_2 emissions year-round according to 40 CFR part 75, you must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O by following the requirements of subpart C.

(c) For each stationary fuel combustion unit that does not generate electricity, you must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O by following the requirements of subpart C of this part.

§ 98.43 Calculating GHG emissions.

Continue to monitor and report CO_2 mass emissions as required under § 75.13 or section 2.3 of apppendix G to 40 CFR part 75, and § 75.64. Calculate CO_2, CH_4, and N_2O emissions as follows:

(a) Convert the cumulative annual CO_2 mass emissions reported in the fourth quarter electronic data report required under § 75.64 from units of short tons to metric tons. To convert tons to metric tons, divide by 1.1023.

(b) Calculate and report annual CH_4 and N_2O mass emissions under this subpart by following the applicable method specified in § 98.33(c).

§ 98.44 Monitoring and QA/QC requirements.

Follow the applicable quality assurance procedures for CO_2 emissions in appendices B, D, and G to 40 CFR part 75.

§ 98.45 Procedures for estimating missing data.

Follow the applicable missing data substitution procedures in 40 CFR part 75 for CO_2 concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

§ 98.46 Data reporting requirements.

The annual report shall comply with the data reporting requirements specified in § 98.36(b) and, if applicable, § 98.36(c)(2) or (c)(3).

§ 98.47 Records that must be retained.

You shall comply with the recordkeeping requirements of §§ 98.3(g) and 98.37.

§ 98.48 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart E—Adipic Acid Production

§ 98.50 Definition of source category.

The adipic acid production source category consists of all adipic acid production facilities that use oxidation to produce adipic acid.

§ 98.51 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an adipic acid production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.52 GHGs to report.

(a) You must report N_2O process emissions at the facility level.

(b) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary combustion unit following the requirements of subpart C.

§ 98.53 Calculating GHG emissions.

(a) You must determine annual N_2O emissions from adipic acid production according to paragraphs (a)(1) or (a)(2) of this section.

(1) Use a site-specific emission factor and production data according to paragraphs (b) through (h) of this section.

(2) Request Administrator approval for an alternative method of determining N_2O emissions according to paragraphs (a)(2)(i) and (a)(2)(ii) of this section.

(i) You must submit the request within 45 days following promulgation of this subpart or within the first 30 days of each subsequent reporting year.

(ii) If the Administrator does not approve your requested alternative method within 150 days of the end of the reporting year, you must determine the N_2O emissions factor for the current reporting period using the procedures specified in paragraphs (b) through (h) of this section.

(b) You must conduct an annual performance test according to paragraphs (b)(1) through (b)(3) of this section.

(1) You must conduct the test on the waste gas stream from the nitric acid oxidation step of the process using the methods specified in § 98.54(b) through (d).

(2) You must conduct the performance test under normal process operating conditions and without using N_2O abatement technology.

(3) You must measure the adipic acid production rate during the test and calculate the production rate for the test period in metric tons per hour.

(c) You must determine an N_2O emissions factor to use in Equation E–2 of this section according to paragraphs (c)(1) or (c)(2) of this section.

(1) You may request Administrator approval for an alternative method of determining N_2O concentration according to the procedures in paragraphs (a)(2)(i) and (a)(2)(ii) of this section. Alternative methods include the use of N_2O CEMs.

(2) Using the results of the performance test in paragraph (b) of this section, you must calculate a facility-specific emissions factor according to Equation E–1 of this section:

$$EF_{N2O} = \frac{\sum_{1}^{n} \frac{C_{N2O} * 1.14 \times 10^{-7} * Q}{P}}{n} \qquad \text{(Eq. E-1)}$$

Where:

EF_{N2O} = Average facility-specific N_2O emissions factor (lb N_2O generated/ton adipic acid produced).

C_{N2O} = N_2O concentration per text run during the performance test (ppm N_2O).

1.14×10^{-7} = Conversion factor (lb/dscf-ppm N_2O).

Q = Volumetric flow rate of effluent gas per test run during the performance test (dscf/hr).

P = Production rate per test run during the performance test (tons adipic acid produced/hr).

n = Number of test runs.

(d) If applicable, you must determine the destruction efficiency for each N_2O abatement technology used at your facility according to paragraphs (d)(1), (d)(2), or (d)(3) of this section.

(1) Use the manufacturer's specified destruction efficiency.

(2) Estimate the destruction efficiency through process knowledge. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current vent stream conditions. You must document how process knowledge was used to determine the destruction efficiency.

(3) Calculate the destruction efficiency by conducting an additional performance test on the emissions stream following the N_2O abatement technology.

(e) If applicable, you must determine the abatement factor for each N_2O abatement technology used at your facility. The abatement factor is calculated for each adipic acid facility according to Equation E–2 of this section.

$$AF_N = \frac{P_{a\,Abate}}{P_a} \qquad \text{(Eq. E-2)}$$

Where:

AF_N = Abatement factor of N_2O abatement technology (fraction of annual production that abatement technology is operating).

$P_{a\,Abate}$ = Annual adipic acid production during which N_2O abatement was used.

P_a = Total annual adipic acid production (ton acid produced).

(f) You must determine the annual amount of adipic acid produced and the annual adipic acid production during which N_2O abatement is operating.

(g) You must calculate annual adipic acid production process emissions of N_2O by multiplying the emissions factor (determined using Equation E–1 of this section) by the total annual adipic acid production and accounting for N_2O abatement, according to Equation E–3 of this section:

$$N_2O = \sum_{1}^{N} \frac{EF_{N2O} * P_a * \left(1 - \left(DF_N * AF_N\right)\right)}{2205} \qquad \text{(Eq. E-3)}$$

Where:

N_2O = Annual N_2O mass emissions from adipic acid production (metric tons).

EF_{N2O} = Facility-specific N_2O emissions factor (lb N_2O generated/ton adipic acid produced).

P_a = Annual adipic acid produced (tons).

DF_N = Destruction efficiency of N_2O abatement technology N (abatement device destruction efficiency, percent of N_2O removed from air stream).

AF_N = Abatement factor of N_2O abatement technology N (fraction of annual production abatement technology is operating).

2205 = Conversion factor (lb/metric ton).

N = Number of different N_2O abatement technologies.

(h) You must determine the amount of process N_2O emissions that is sold or transferred off site (if applicable). You can determine the amount using existing process flow meters and N_2O analyzers.

§ 98.54 Monitoring and QA/QC requirements.

(a) You must conduct a new performance test and calculate a new facility-specific emissions factor according to the frequency specified in paragraphs (a)(1) through (a)(3) of this section.

(1) Conduct the performance test annually.

(2) Conduct the performance test when your adipic acid production process is changed either by altering the ratio of cyclohexanone to cyclohexanol or by installing abatement equipment.

(3) If you requested Administrator approval for an alternative method of determining N_2O concentration under § 98.53(a)(2), you must conduct the performance test if your request has not been approved by the Administrator within 150 days of the end of the reporting year in which it was submitted.

(b) You must measure the N_2O concentration during the performance test using one of the methods in paragraphs (b)(1) through (b)(3) of this section.

(1) EPA Method 320, Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier

Transform Infrared (FTIR) Spectroscopy in 40 CFR part 63, Appendix A;

(2) ASTM D6348–03 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy (incorporated by reference, *see* § 98.7); or

(3) An equivalent method, with Administrator approval.

(c) You must determine the production rate(s) during the performance test according to paragraph (c)(1) or (c)(2) of this section.

(1) Direct measurement (such as using flow meters or weigh scales).

(2) Existing plant procedures used for accounting purposes.

(d) You must conduct all required performance tests according to the methods in § 98.54(b) in conjunction with the applicable EPA methods in 40 CFR part 60, appendices A–1 through A–4. Conduct three emissions test runs of 1 hour each. All QA/QC procedures specified in the reference test methods and any associated performance specifications apply. For each test, the facility must prepare an emissions factor determination report that must include the items in paragraphs (d)(1) through (d)(3) of this section:

(1) Analysis of samples, determination of emissions, and raw data.

(2) All information and data used to derive the emissions factor.

(3) The production rate(s) during the performance test and how each production rate was determined.

(e) You must determine the monthly adipic acid production quantity and the monthly adipic acid production during which N_2O abatement technology is operating according to the methods in paragraphs (c)(1) or (c)(2) of this section.

(f) You must determine the annual adipic acid production quantity and the annual adipic production quantity during which N_2O abatement technology is operating by summing the respective monthly adipic acid production quantities.

§ 98.55 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section.

(a) For each missing value of monthly adipic acid production, the substitute data shall be the best available estimate based on all available process data or data used for accounting purposes (such as sales records).

(b) For missing values related to the performance test, including emission factors, production rate, and N_2O concentration, you must conduct a new performance test according to the procedures in § 98.54 (a) through (d).

§ 98.56 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) through (k) of this section at the facility level:

(a) Annual process N_2O emissions from adipic acid production (metric tons).

(b) Annual adipic acid production (tons).

(c) Annual adipic acid production during which N_2O abatement technology is operating (tons).

(d) Annual process N_2O emissions from adipic acid production facility that is sold or transferred off site (metric tons).

(e) Number of abatement technologies (if applicable).

(f) Types of abatement technologies used (if applicable).

(g) Abatement technology destruction efficiency for each abatement technology (percent destruction).

(h) Abatement utilization factor for each abatement technology (fraction of annual production that abatement technology is operating).

(i) Number of times in the reporting year that missing data procedures were followed to measure adipic acid production (months).

(j) If you conducted a performance test and calculated a site-specific emissions factor according to § 98.53(a)(1), each annual report must also contain the information specified in paragraphs (j)(1) through (j)(7) of this section for each adipic acid production facility.

(1) Emissions factor (lb N_2O/ton adipic acid).

(2) Test method used for performance test.

(3) Production rate per test run during performance test (tons/hr).

(4) N_2O concentration per test run during performance test (ppm N_2O).

(5) Volumetric flow rate per test run during performance test (dscf/hr).

(6) Number of test runs.

(7) Number of times in the reporting year that a performance test had to be repeated (number).

(k) If you requested Administrator approval for an alternative method of determining N_2O concentration under § 98.53(a)(2), each annual report must also contain the information specified in paragraphs (k)(1) through (k)(4) of this section for each adipic acid production facility.

(1) Name of alternative method.

(2) Description of alternative method.

(3) Request date.

(4) Approval date.

§ 98.57 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the records specified in paragraphs (a) through (h) of this section at the facility level:

(a) Annual adipic acid production capacity (tons).

(b) Records of significant changes to process.

(c) Number of facility operating hours in calendar year.

(d) Documentation of how accounting procedures were used to estimate production rate.

(e) Documentation of how process knowledge was used to estimate abatement technology destruction efficiency.

(f) Performance test reports of N_2O emissions.

(g) Measurements, records and calculations used to determine reported parameters.

(h) Documentation of the procedures used to ensure the accuracy of the measurements of all reported parameters, including but not limited to, calibration of weighing equipment, flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§ 98.58 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart F—Aluminum Production

§ 98.60 Definition of the source category.

(a) A primary aluminum production facility manufactures primary aluminum using the Hall-Héroult manufacturing process. The primary aluminum manufacturing process comprises the following operations:

(1) Electrolysis in prebake and Søderberg cells.

(2) Anode baking for prebake cells.

(b) This source category does not include experimental cells or research and development process units.

§ 98.61 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an aluminum production process and the facility meets the requirements of either § 98.2(a)(1) or (a)(2).

§ 98.62 GHGs to report.

You must report:

(a) Perfluoromethane (CF_4), and perfluoroethane (C_2F_6) emissions from anode effects in all prebake and Søderberg electolysis cells.

(b) CO_2 emissions from anode consumption during electrolysis in all prebake and Søderberg electolysis cells.

(c) CO_2 emissions from on-site anode baking.

(d) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, N_2O, and CH_4 emissions from each stationary fuel combustion unit by following the requirements of subpart C.

§ 98.63 Calculating GHG emissions.

(a) The annual value for PFC emissions shall be estimated from the sum of monthly values using Equation F–1 of this section:

$$E_{PFC} = \sum_{m=1}^{m=12} E_m \qquad \text{(Eq. F-1)}$$

Where:

E_{PFC} = Annual PFC emissions from aluminum production (metric tons PFC).

E_m = PFC emissions from aluminum production for the month ''m'' (metric tons PFC).

(b) Use Equation F–2 of this section to estimate CF_4 emissions from anode effect duration or Equation F–3 of this section to estimate CF_4 emissions from overvoltage, and use Equation F–4 of this section to estimate C_2F_6 emissions from anode effects from each prebake and Søderberg electrolysis cell.

$$E_{CF4} = S_{CF4} \times AEM \times MP \times 0.001 \qquad \text{(Eq. F-2)}$$

Where:

E_{CF4} = Monthly CF_4 emissions from aluminum production (metric tons CF_4).

S_{CF4} = The slope coefficient ((kg CF_4/metric ton Al)/(AE-Mins/cell-day)).

AEM = The anode effect minutes per cell-day (AE-Mins/cell-day).

MP = Metal production (metric tons Al), where AEM and MP are calculated monthly.

$$E_{CF4} = EF_{CF4} \times MP \times 0.001 \qquad \text{(Eq. F-3)}$$

Where:

E_{CF4} = Monthly CF_4 emissions from aluminum production (metric tons CF_4).

EF_{CF4} = The overvoltage emission factor (kg CF_4/metric ton Al).

MP = Metal production (metric tons Al), where MP is calculated monthly.

$$E_{C2F6} = E_{CF4} \times F_{C2F6/CF4} \times 0.001 \qquad \text{(Eq. F-4)}$$

Where:

E_{C2F6} = Monthly C_2F_6 emissions from aluminum production (metric tons C_2F_6).

E_{CF4} = CF_4 emissions from aluminum production (kg CF_4).

$F_{C2F6/CF4}$ = The weight fraction of C_2F_6/CF_4 (kg C_2F_6/kg CF_4).

0.001 = Conversion factor from kg to metric tons, where E_{CF4} is calculated monthly.

(c) You must calculate and report the annual process CO_2 emissions from anode consumption during electrolysis and anode baking of prebake cells using either the procedures in paragraph (d) of this section or the procedures in paragraphs (e) and (f) of this section.

(d) Calculate and report under this subpart the process CO_2 emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(e) Use the following procedures to calculate CO_2 emissions from anode consumption during electrolysis:

(1) For Prebake cells: you must calculate CO_2 emissions from anode consumption using Equation F–5 of this section:

$$E_{CO2} = NAC \times MP \times \left([100 - S_a - Ash_a]/100\right) \times (44/12) \qquad \text{(Eq. F-5)}$$

Where:

E_{CO2} = Annual CO_2 emissions from prebaked anode consumption (metric tons CO_2).

NAC = Net annual prebaked anode consumption per metric ton Al (metric tons C/metric tons Al).

MP = Annual metal production (metric tons Al).

S_a = Sulfur content in baked anode (percent weight).

Ash_a = Ash content in baked anode (percent weight).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(2) For Søderberg cells you must calculate CO_2 emissions using Equation F–6 of this section:

$$E_{CO2} = (PC \times MP - [CSM \times MP]/1000 - BC/100 \times PC \times MP \times [S_p + Ash_p + H_p]/100 - [100 - BC]/100 \times PC \times MP \times [S_c + Ash_c]/100 - MP \times CD) \times (44/12) \qquad \text{(Eq. F-6)}$$

Where:

E_{CO2} = Annual CO_2 emissions from paste consumption (metric ton CO_2).
PC = Annual paste consumption (metric ton/metric ton Al).
MP = Annual metal production (metric ton Al).
CSM = Annual emissions of cyclohexane soluble matter (kg/metric ton Al).
BC = Binder content of paste (percent weight).
S_p = Sulfur content of pitch (percent weight).
Ash_p = Ash content of pitch (percent weight).
H_p = Hydrogen content of pitch (percent weight).
S_c = Sulfur content in calcined coke (percent weight).
Ash_c = Ash content in calcined coke (percent weight).
CD = Carbon in skimmed dust from Søderberg cells (metric ton C/metric ton Al).
44/12 = Ratio of molecular weights, CO_2 to carbon.

(f) Use the following procedures to calculate CO_2 emissions from anode baking of prebake cells:

(1) Use Equation F–7 of this section to calculate emissions from pitch volatiles combustion.

$$E_{CO2PV} = \left(GA - H_w - BA - WT\right) \times (44/12) \qquad \text{(Eq. F-7)}$$

Where:

E_{CO2PV} = Annual CO_2 emissions from pitch volatiles combustion (metric tons CO_2).
GA = Initial weight of green anodes (metric tons).
H_w = Annual hydrogen content in green anodes (metric tons).
BA = Annual baked anode production (metric tons).
WT = Annual waste tar collected (metric tons).
44/12 = Ratio of molecular weights, CO_2 to carbon.

(2) Use Equation F–8 of this section to calculate emissions from bake furnace packing material.

$$E_{CO2PC} = PCC \times BA \times \left(\left[100 - S_{pc} - Ash_{pc}\right]/100\right) \times (44/12) \qquad \text{(Eq. F-8)}$$

Where:

E_{CO2PC} = Annual CO_2 emissions from bake furnace packing material (metric tons CO_2).
PCC = Annual packing coke consumption (metric tons/metric ton baked anode).
BA = Annual baked anode production (metric tons).
S_{pc} = Sulfur content in packing coke (percent weight).
Ash_{pc} = Ash content in packing coke (percent weight).
44/12 = Ratio of molecular weights, CO_2 to carbon.

(g) If process CO_2 emissions from anode consumption during electrolysis or anode baking of prebake cells are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraphs (d) and (e) of this section shall not be used to calculate those process emissions. The owner or operation shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

§ 98.64 Monitoring and QA/QC requirements.

(a) Effective one year after publication of the rule for smelters with no prior measurement or effective three years after publication for facilities with historic measurements, the smelter-specific slope coefficients used in Equations F–2, F–3, and F–4 of this subpart must be measured in accordance with the recommendations of the EPA/IAI Protocol for Measurement of Tetrafluoromethane (CF_4) and Hexafluoroethane (C_2F_6) Emissions from Primary Aluminum Production (2008), except the minimum frequency of measurement shall be every 10 years unless a change occurs in the control algorithm that affects the mix of types of anode effects or the nature of the anode effect termination routine. Facilities which operate at less than 0.2 anode effect minutes per cell day or operate with less than 1.4mV anode effect overvoltage can use either smelter-specific slope coefficients or the technology specific default values in Table F–1 of this subpart.

(b) The minimum frequency of the measurement and analysis is annually except as follows: Monthly—anode effect minutes per cell day (or anode effect overvoltage and current efficiency), production.

(c) Sources may use either smelter-specific values from annual measurements of parameters needed to complete the equations in § 98.63 (e.g., sulfur, ash, and hydrogen contents) or the default values shown in Table F–2 of this subpart.

§ 98.65 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required sample measurement is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the following requirements:

(a) Where anode or paste consumption data are missing, CO_2 emissions can be estimated from aluminum production using Tier 1 method per Equation F–8 of this section.

$$ECO_2 = EF_p \text{ x } MP_p + EF_s \text{ x } MP_s \qquad \text{(Eq. F-8)}$$

Where:

ECO_2 = CO_2 emissions from anode and/or paste consumption, metric tons CO_2.
EF_p = Prebake technology specific emission factor (1.6 metric tons CO_2/metric ton aluminum produced).
MP_p = Metal production from prebake process (metric tons Al).
EF_s = Søderberg technology specific emission factor (1.7 metric tons CO_2/metric ton Al produced).
MP_s = Metal production from Søderberg process (metric tons Al).

(b) For other parameters, use the average of the two most recent data points after the missing data.

§ 98.66 Data reporting requirements.

In addition to the information required by § 98.3(c), you must report the following information at the facility level:

(a) Annual aluminum production in metric tons.

(b) Type of smelter technology used.

(c) The following PFC-specific information on an annual basis:

(1) Perfluoromethane emissions and perfluoroethane emissions from anode effects in all prebake and all Søderberg electolysis cells combined.

(2) Anode effect minutes per cell-day (AE-mins/cell-day), anode effect frequency (AE/cell-day), anode effect duration (minutes). (Or anode effect overvoltage factor ((kg CF_4/metric ton Al)/(mV/cell day)), potline overvoltage (mV/cell day), current efficiency (%).)

(3) Smelter-specific slope coefficients (or overvoltage emission factors) and the last date when the smelter-specific-slope coefficients (or overvoltage emission factors) were measured.

(d) Method used to measure the frequency and duration of anode effects (or overvoltage).

(e) The following CO_2-specific information for prebake cells:

(1) Annual anode consumption.

(2) Annual CO_2 emissions from the smelter.

(f) The following CO_2-specific information for Søderberg cells:

(1) Annual paste consumption.

(2) Annual CO_2 emissions from the smelter.

(g) Smelter-specific inputs to the CO_2 process equations (e.g., levels of sulfur and ash) that were used in the calculation, on an annual basis.

(h) Exact data elements required will vary depending on smelter technology (e.g., point-feed prebake or Søderberg) and process control technology (e.g., Pechiney or other).

§ 98.67 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the following records:

(a) Monthly aluminum production in metric tons.

(b) Type of smelter technology used.

(c) The following PFC-specific information on a monthly basis:

(1) Perfluoromethane and perfluoroethane emissions from anode effects in prebake and Søderberg electolysis cells.

(2) Anode effect minutes per cell-day (AE-mins/cell-day), anode effect frequency (AE/cell-day), anode effect duration (minutes). (Or anode effect overvoltage factor ((kg CF_4/metric ton Al)/(mV/cell day)), potline overvoltage (mV/cell day), current efficiency (%).))

(3) Smelter-specific slope coefficients and the last date when the smelter-specific-slope coefficients were measured.

(d) Method used to measure the frequency and duration of anode effects (or to measure anode effect overvoltage and current efficiency).

(e) The following CO_2-specific information for prebake cells:

(1) Annual anode consumption.

(2) Annual CO_2 emissions from the smelter.

(f) The following CO_2-specific information for Søderberg cells:

(1) Annual paste consumption.

(2) Annual CO_2 emissions from the smelter.

(g) Smelter-specific inputs to the CO_2 process equations (e.g., levels of sulfur and ash) that were used in the calculation, on an annual basis.

(h) Exact data elements required will vary depending on smelter technology (e.g., point-feed prebake or Søderberg) and process control technology (e.g., Pechiney or other).

§ 98.68 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE F–1 TO SUBPART F OF PART 98—SLOPE AND OVERVOLTAGE COEFFICIENTS FOR THE CALCULATION OF PFC EMISSIONS FROM ALUMINUM PRODUCTION

Technology	CF_4 slope coefficient [(kg CF_4/metric ton Al)/(AE-Mins/cell-day)]	CF_4 overvoltage coefficient [(kg CF_4/metric ton Al)/(mV)]	Weight fraction C_2F_6/CF_4 [(kg C_2F_6/kg CF_4)]
CWPB	0.143	1.16	0.121
SWPB	0.272	3.65	0.252
VSS	0.092	NA	0.053
HSS	0.099	NA	0.085

TABLE F–2 TO SUBPART F OF PART 98—DEFAULT DATA SOURCES FOR PARAMETERS USED FOR CO_2 EMISSIONS

Parameter	Data source
CO_2 Emissions from Prebake Cells (CWPB and SWPB)	
MP: metal production (metric tons Al)	Individual facility records.
NAC: net annual prebaked anode consumption per metric ton Al (metric tons C/metric tons Al)	Individual facility records.
S_a: sulfur content in baked anode (percent weight)	2.0.
Ash_a: ash content in baked anode (percent weight)	0.4.
CO_2 Emissions from Søderberg Cells (VSS and HSS)	
MP: metal production (metric tons Al)	Individual facility records.
PC: annual paste consumption (metric ton/metric ton Al)	Individual facility records.
CSM: annual emissions of cyclohexane soluble matter (kg/metric ton Al)	HSS: 4.0. VSS: 0.5.
BC: binder content of paste (percent weight)	Dry Paste: 24. Wet Paste: 27.
S_p: sulfur content of pitch (percent weight)	0.6.
Ash_p: ash content of pitch (percent weight)	0.2.

TABLE F–2 TO SUBPART F OF PART 98—DEFAULT DATA SOURCES FOR PARAMETERS USED FOR CO_2 EMISSIONS—Continued

Parameter	Data source
H_p: hydrogen content of pitch (percent weight)	3.3.
S_c: sulfur content in calcined coke (percent weight)	1.9.
Ash_c: ash content in calcined coke (percent weight)	0.2.
CD: carbon in skimmed dust from Søderberg cells (metric ton C/metric ton Al)	0.01.
CO_2 Emissions from Pitch Volatiles Combustion (VSS and HSS)	
GA: initial weight of green anodes (metric tons)	Individual facility records.
H_w: annual hydrogen content in green anodes (metric tons)	0.005 × GA.
BA: annual baked anode production (metric tons)	Individual facility records.
WT: annual waste tar collected (metric tons)	
(a) Riedhammer furnaces	(a) 0.005 × GA.
(b) all other furnaces.	(b) insignificant.
CO_2 Emissions From Bake Furnace Packing Materials (CWPB and SWPB)	
PCC: annual packing coke consumption (metric tons/metric ton baked anode)	0.015.
BA: annual baked anode production (metric tons)	Individual facility records.
S_{pc}: sulfur content in packing coke (percent weight)	2.
Ash_{pc}: ash content in packing coke (percent weight)	2.5.

Subpart G—Ammonia Manufacturing

§ 98.70 Definition of source category.

The ammonia manufacturing source category comprises the process units listed in paragraphs (a) and (b) of this section.

(a) Ammonia manufacturing processes in which ammonia is manufactured from a fossil-based feedstock produced via steam reforming of a hydrocarbon.

(b) Ammonia manufacturing processes in which ammonia is manufactured through the gasification of solid and liquid raw material.

§ 98.71 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an ammonia manufacturing process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.72 GHGs to report.

You must report:

(a) CO_2 process emissions from steam reforming of a hydrocarbon or the gasification of solid and liquid raw material, reported for each ammonia manufacturing process unit following the requirements in this subpart.

(b) CO_2, CH_4, and N_2O emissions from each stationary fuel combustion unit. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources), by following the requirements of subpart C.

(c) CO_2 emissions collected and transferred off site under subpart PP of this part (Suppliers of CO_2), following the requirements of subpart PP.

§ 98.73 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each ammonia manufacturing process unit using the procedures in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the process CO_2 emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart process CO_2 emissions using the procedures in paragraphs (b)(1) through (b)(6) of this section for gaseous feedstock, liquid feedstock, or solid feedstock, as applicable.

(1) *Gaseous feedstock.* You must calculate, from each ammonia manufacturing unit, the CO_2 process emissions from gaseous feedstock according to Equation G–1 of this section:

$$CO_{2,G,k} = \left(\sum_{n=1}^{12} \frac{44}{12} * Fdstk_{n,k} * CC_n * \frac{MW}{MVC} \right) * 0.001 \qquad \text{(Eq. G-1)}$$

Where:

$CO_{2,G}$ = Annual CO_2 emissions arising from feedstock consumption (metric tons).

$Fdstk_n$ = Volume of the gaseous feedstock used in month n (scf of feedstock).

CC_n = Carbon content of the gaseous feedstock, for month n (kg C per kg of feedstock), determined according to 98.74(c).

MW = Molecular weight of the gaseous feedstock (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

k = Processing unit.

n = Number of month.

(2) *Liquid feedstock.* You must calculate, from each ammonia manufacturing unit, the CO_2 process emissions from liquid feedstock according to Equation G–2 of this section:

$$CO_{2,L,k} = \left(\sum_{n=1}^{12} \frac{44}{12} * Fdstk_{n,k} * CC_n \right) * 0.001 \qquad \text{(Eq. G-2)}$$

Where:

$CO_{2,L}$ = Annual CO_2 emissions arising from feedstock consumption (metric tons).

$Fdstk_n$ = Volume of the liquid feedstock used in month n (gallons of feedstock).

CC_n = Carbon content of the liquid feedstock, for month n (kg C per gallon of feedstock) determined according to 98.74(c).

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

k = Processing unit.

n = Number of month.

(3) *Solid feedstock*. You must calculate, from each ammonia manufacturing unit, the CO_2 process emissions from solid feedstock according to Equation G–3 of this section:

$$CO_{2,S,k} = \left(\sum_{n=1}^{12} \frac{44}{12} * Fdstk_{n,k} * CC_n \right) * 0.001 \qquad \text{(Eq. G-3)}$$

Where:

$CO_{2,S}$ = Annual CO_2 emissions arising from feedstock consumption (metric tons).

$Fdstk_n$ = Mass of the solid feedstock used in month n (kg of feedstock).

CC_n = Carbon content of the solid feedstock, for month n (kg C per kg of feedstock), determined according to 98.74(c).

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

k = Processing unit.

n = Number of month.

(4) You must calculate the annual process CO_2 emissions from each ammonia processing unit k at your facility summing emissions, as applicable from Equation G–1, G–2, and G–3 of this section using Equation G–4.

$$E_{CO2_k} = CO_{2,G} + CO_{2,S} + CO_{2,L} \qquad \text{(Eq. G-4)}$$

Where:

E_{CO2_k} = Annual CO_2 emissions from each ammonia processing unit k (metric tons).

k = Processing unit.

(5) You must determine the combined CO_2 emissions from all ammonia processing units at your facility using Equation G–5 of this section.

$$CO_2 = \sum_{k=1}^{n} E_{CO2_k} \qquad \text{(Eq. G-5)}$$

Where:

CO_2 = Annual combined CO_2 emissions from all ammonia processing units (metric tons).

E_{CO2_k} = Annual CO_2 emissions from each ammonia processing unit (metric tons).

k = Processing unit.

n = Total number of ammonia processing units.

(6) If applicable, ammonia manufacturing facilities that utilize the waste recycle stream as a fuel must calculate emissions associated with the waste stream for each ammonia process unit according to Equation G–6 of this section:

$$CO_2 = \left(\sum_{n=1}^{12} \frac{44}{12} * RecycleStream_n * CC_n * \frac{MW}{MVC} \right) \star 0.001 \qquad \text{(Eq. G-6)}$$

Where:

CO_2 = Annual CO_2 contained in waste recycle stream (metric tons).

$RecycleStream_n$ = Volume of the waste recycle stream in month n (scf).

CC_n = Carbon content of the waste recycle stream, for month n (kg C per kg of waste recycle stream) determined according to 98.74(f).

MW = Molecular weight of the waste recycle stream (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

n = Number of month

(c) If GHG emissions from an ammonia manufacturing unit are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

§ 98.74 Monitoring and QA/QC requirements.

(a) You must continuously measure the quantity of gaseous or liquid feedstock consumed using a flow meter. The quantity of solid feedstock consumed can be obtained from company records and aggregated on a monthly basis.

(b) You must document the procedures used to ensure the accuracy of the estimates of feedstock consumption.

(c) You must determine monthly carbon contents and the average molecular weight of each feedstock consumed from reports from your supplier. As an alternative to using supplier information on carbon contents, you can also collect a sample of each feedstock on a monthly basis and analyze the carbon content and molecular weight of the fuel using any of the following methods listed in paragraphs (c)(1) through (c)(8) of this section, as applicable.

(1) ASTM D1945–03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, *see* § 98.7).

(2) ASTM D1946–90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, *see* § 98.7).

(3) ASTM D2502–04 (Reapproved 2002) Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils from Viscosity Measurements (incorporated by reference, *see* § 98.7).

(4) ASTM D2503–92 (Reapproved 2007) Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure (incorporated by reference, *see* § 98.7).

(5) ASTM D3238–95 (Reapproved 2005) Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method (incorporated by reference, *see* § 98.7).

(6) ASTM D5291–02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, *see* § 98.7).

(7) ASTM D3176–89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, *see* § 98.7).

(8) ASTM D5373–08 Standard Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, *see* § 98.7).

(d) Calibrate all oil and gas flow meters (except for gas billing meters) and perform oil tank measurements according to the monitoring and QA/QC requirements for the Tier 3 methodology in § 98.34(b).

(e) For quality assurance and quality control of the supplier data, on an annual basis, you must measure the carbon contents of a representative sample of the feedstocks consumed using the appropriate ASTM Method as listed in paragraphs (c)(1) through (c)(8) of this section.

(f) Facilities must continuously measure the quantity of waste gas recycled using a flow meter, as applicable. You must determine the carbon content and the molecular weight of the waste recycle stream by collecting a sample of each waste recycle stream on a monthly basis and analyzing the carbon content using the appropriate ASTM Method as listed in paragraphs (c)(1) through (c)(8) of this section.

(g) If CO_2 from ammonia production is used to produce urea at the same facility, you must determine the quantity of urea produced using methods or plant instruments used for accounting purposes (such as sales records). You must document the procedures used to ensure the accuracy of the estimates of urea produced.

§ 98.75 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever the monitoring and quality assurance procedures in § 98.74 cannot be followed (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter shall be used in the calculations following paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For missing data on monthly carbon contents of feedstock or the waste recycle stream, the substitute data value shall be the arithmetic average of the quality-assured values of that carbon content in the month preceding and the month immediately following the missing data incident. If no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon content obtained in the month after the missing data period.

(b) For missing feedstock supply rates or waste recycle stream used to determine monthly feedstock consumption or monthly waste recycle stream quantity, you must determine the best available estimate(s) of the parameter(s), based on all available process data.

§ 98.76 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) and (b) of this section, as applicable for each ammonia manufacturing process unit.

(a) If a CEMS is used to measure CO_2 emissions, then you must report the relevant information required under § 98.37(e)(2)(vi) for the Tier 4 Calculation Methodology and the following information in this paragraph (a):

(1) Annual quantity of each type of feedstock consumed for ammonia manufacturing (scf of feedstock or gallons of feedstock or kg of feedstock).

(2) Method used for determining quantity of feedstock used.

(b) If a CEMS is not used to measure emissions, then you must report the following information:

(1) Annual CO_2 process emissions (metric tons) for each ammonia manufacturing process unit.

(2) Monthly quantity of each type of feedstock consumed for ammonia manufacturing for each ammonia processing unit (scf of feedstock or gallons of feedstock or kg of feedstock).

(3) Method used for determining quantity of monthly feedstock used.

(4) Whether carbon content for each feedstock for month n is based on reports from the supplier or analysis of carbon content.

(5) If carbon content of feedstock for month n is based on analysis, the test method used.

(6) Sampling analysis results of carbon content of petroleum coke as determined for QA/QC of supplier data under § 98.74(e).

(7) If a facility uses gaseous feedstock, the carbon content of the gaseous feedstock, for month n, (kg C per kg of feedstock).

(8) If a facility uses gaseous feedstock, the molecular weight of the gaseous feedstock (kg/kg-mole).

(9) If a facility uses gaseous feedstock, the molar volume conversion factor of the gaseous feedstock (scf per kg-mole).

(10) If a facility uses liquid feedstock, the carbon content of the liquid feedstock, for month n, (kg C per gallon of feedstock).

(11) If a facility uses solid feedstock, the carbon content of the solid feedstock, for month n, (kg C per kg of feedstock).

(12) Annual CO_2 emissions associated with the waste recycle stream for each ammonia process unit (metric tons)

(13) Carbon content of the waste recycle stream for month n for each ammonia process unit (kg C per kg of waste recycle stream).

(14) Volume of the waste recycle stream for month n for each ammonia process unit (scf)

(15) Method used for analyzing carbon content of waste recycle stream.

(16) Annual urea production (metric tons) and method used to determine urea production.

(17) Uses of urea produced, if known, such as but not limited to fertilizer, animal feed, manufacturing of plastics or resins, and pollution control technologies.

(c) Total pounds of synthetic fertilizer produced through and total nitrogen contained in that fertilizer.

§ 98.77 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the following records specified in paragraphs (a) and (b) of this section for each ammonia manufacturing unit.

(a) If a CEMS is used to measure emissions, retain records of all feedstock purchases in addition to the requirements in § 98.37 for the Tier 4 Calculation Methodology.

(b) If a CEMS is not used to measure process CO_2 emissions, you must also retain the records specified in paragraphs (b)(1) through (b)(2) of this section:

(1) Records of all analyses and calculations conducted for reported data as listed in § 98.76(b).

(2) Monthly records of carbon content of feedstock from supplier and/or all analyses conducted of carbon content.

§ 98.78 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart H—Cement Production

§ 98.80 Definition of the source category.

The cement production source category consists of each kiln and each in-line kiln/raw mill at any portland cement manufacturing facility including alkali bypasses, and includes kilns and in-line kiln/raw mills that burn hazardous waste.

§ 98.81 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a cement production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.82 GHGs to report.

You must report:

(a) CO_2 process emissions from calcination in each kiln.

(b) CO_2 combustion emissions from each kiln.

(c) CH_4 and N_2O combustion emissions from each kiln. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) CO_2, CH_4, and N_2O emissions from each stationary combustion unit other than kilns. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§ 98.83 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each kiln using the procedure in paragraphs (a) and (b) of this section.

(a) For each cement kiln that meets the conditions specified in § 98.33(b)(4)(ii) or (b)(4)(iii), you must calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For each kiln that is not subject to the requirements in paragraph (a) of this section, calculate and report the process and combustion CO_2 emissions from the kiln by using the procedure in either paragraph (c) or (d) of this section.

(c) Calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(d) Calculate and report process and combustion CO_2 emissions separately using the procedures specified in paragraphs (d)(1) through (d)(4) of this section.

(1) Calculate CO_2 process emissions from all kilns at the facility using Equation H–1 of this section:

$$CO_{2CMF} = \sum_{m=1}^{k} CO_{2Cli,m} + CO_{2rm} \qquad \text{(Eq. H-1)}$$

Where:

$CO_{2\,CMF}$ = Annual process emissions of CO_2 from cement manufacturing, metric tons.

$CO_{2\,Cli,m}$ = Total annual emissions of CO_2 from clinker production from kiln m, metric tons.

$CO_{2\,rm}$ = Total annual emissions of CO_2 from raw materials, metric tons.

k = Total number of kilns at a cement manufacturing facility.

(2) *CO_2 emissions from clinker production.* Calculate CO_2 emissions from each kiln using Equations H–2 through H–5 of this section.

$$CO_{2\ Cli,m} = \sum_{j=1}^{p}\left[\left(Cli_{,j}\right)*\left(EF_{Cli,j}\right)*\frac{2000}{2205}\right] + \sum_{i=1}^{r}\left[\left(CKD_{,i}\right)*\left(EF_{CKD,i}\right)*\frac{2000}{2205}\right] \qquad \text{(Eq. H-2)}$$

Where:

$Cli_{,j}$ = Quantity of clinker produced in month j from kiln m, tons.

$EF_{Cli,j}$ = Kiln specific clinker emission factor for month j for kiln m, metric tons CO_2/metric ton clinker computed as specified in Equation H–3 of this section.

$CKD_{,i}$ = Cement kiln dust (CKD) not recycled to the kiln in quarter i from kiln m, tons.

$EF_{CKD,i}$ = Kiln specific CKD emission factor for quarter i from kiln m, metric tons CO_2/metric ton CKD computed as specified in Equation H–4 of this section.

p = Number of months for clinker calculation, 12.

r = Number of quarters for CKD calculation, 4.

2000/2205 = Conversion factor to convert tons to metric tons.

(i) *Kiln-Specific Clinker Emission Factor.* (A) Calculate the kiln-specific clinker emission factor using Equation H–3 of this section.

$$EF_{\mathrm{Cli}} = \left(CLi_{CaO} - Cli_{ncCaO}\right)*MR_{CaO} + \left(Cli_{MgO} - Cli_{ncMgO}\right)*MR_{MgO} \qquad \text{(Eq. H-3)}$$

Where:

Cli_{CaO} = Monthly total CaO content of Clinker, wt-fraction.
Cli_{ncCaO} = Monthly non-calcined CaO content of Clinker, wt-fraction.
MR_{CaO} = Molecular-weight Ratio of CO_2/CaO = 0.785.
Cli_{MgO} = Monthly total MgO content of Clinker, wt-fraction.
Cli_{ncMgO} = Monthly non-calcined MgO content of Clinker, wt-fraction.
MR_{MgO} = Molecular-weight Ratio of CO_2/MgO = 1.092.

(B) Non-calcined CaO is CaO that remains in the clinker in the form of $CaCO_3$ and CaO in the clinker that entered the kiln as a non-carbonate species. Non-calcined MgO is MgO that remains in the clinker in the form of $MgCO_3$ and MgO in the clinker that entered the kiln as a non-carbonate species.

(ii) *Kiln-Specific CKD Emission Factor.* (A) Calculate the kiln-specific CKD emission factor for CKD not recycled to the kiln using Equation H–4 of this section.

$$EF_{\mathrm{CKD}} = \left(CKD_{CaO} - CKD_{ncCaO}\right) * MR_{CaO} + \left(CKD_{MgO} - CKD_{ncMgO}\right) * MR_{MgO} \qquad \text{(Eq. H-4)}$$

Where:

CKD_{CaO} = Quarterly total CaO content of CKD not recycled to the kiln, wt-fraction.
CKD_{CaO} = Quarterly non-calcined CaO content of CKD not recycled to the kiln, wt-fraction.
MR_{CaO} = Molecular-weight Ratio of CO_2/CaO = 0.785.
CKD_{MgO} = Quarterly total MgO content of CKD not recycled to the kiln, wt-fraction.
CKD_{MgO} = Quarterly non-calcined MgO content of CKD not recycled to the kiln, wt-fraction.
MR_{MgO} = Molecular-weight Ratio of CO_2/MgO = 1.092.

(B) Non-calcined CaO is CaO that remains in the CKD in the form of $CaCO_3$ and CaO in the CKD that entered the kiln as a non-carbonate species. Non-calcined MgO is MgO that remains in the CKD in the form of $MgCO_3$ and MgO in the CKD that entered the kiln as a non-carbonate species.

(3) *CO_2 emissions from raw materials.* Calculate CO_2 emissions using Equation H–5 of this section:

$$CO_{2,rm} = \sum_{i=1}^{m} rm \ * \ TOCrm \ * \frac{44}{12} * \frac{2000}{2205} \qquad \text{(Eq. H-5)}$$

Where:

rm = The amount of raw material i consumed annually, tons/yr (dry basis).
$CO_{2,rm}$ = Annual CO_2 emissions from raw materials.
TOCrm = Organic carbon content of raw material i (dry basis), as determined in § 98.84(c) or using a default factor of 0.2 percent of total raw material weight.
M = Number of raw materials.
44/12 = Ratio of molecular weights, CO_2 to carbon.
2000/2205 = Conversion factor to convert tons to metric tons.

(4) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion CO_2 emissions from the kiln according to the applicable requirements in subpart C.

§ 98.84 Monitoring and QA/QC requirements.

(a) You must determine the weight fraction of total CaO and total MgO in CKD not recycled to the kiln from each kiln using ASTM C114–09, Standard Test Methods for Chemical Analysis of Hydraulic Cement (incoporated by reference, see § 98.7). The monitoring must be conducted quarterly for each kiln from a CKD sample drawn either as CKD is exiting the kiln or from bulk CKD storage.

(b) You must determine the weight fraction of total CaO and total MgO in clinker from each kiln using ASTM C114–07 Standard Test Methods for Chemical Analysis of Hydraulic Cement (incorporated by reference, see § 98.7). The monitoring must be conducted monthly for each kiln from a clinker sample drawn from bulk clinker storage.

(c) The total organic carbon contents (dry basis) of each raw material must be determined annually using ASTM C114–09 Standard Test Methods for Chemical Analysis of Hydraulic Cement (incorporated by reference, *see* § 98.7) or a similar industry standard practice or method approved for total organic carbon determination in raw mineral materials. The analysis must be conducted on sample material drawn from bulk raw material storage for each category of raw material (i.e., limestone, sand, shale, iron oxide, and alumina). Facilities that opt to use the default total organic carbon factor provided in § 98.83(d)(3), are not required to monitor for TOC.

(d) The quantity of clinker produced monthly by each kiln must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(e) The quantity of CKD not recycled to the kiln by each kiln must be determined quarterly by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers, truck weigh scales, or belt weigh feeders.

(f) The quantity of each category of raw materials consumed annually by the facility (e.g., limestone, sand, shale, iron oxide, and alumina) must be determined monthly by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers, truck weigh scales, or belt weigh feeders.

(g) The monthly non-calcined CaO and MgO that remains in the clinker in the form of $CaCO_3$ or that enters the kiln as a non-carbonate species may be assumed to be a default value of 0.0 or may be determined monthly by careful chemical analysis of feed material and clinker material from each kiln using well documented analytical and calculational methods or the appropriate industry standard practice.

(h) The quarterly non-calcined CaO and MgO that remains in the CKD in the form of $CaCO_3$ or that enters the kiln as a non-carbonate species may be assumed to be a default value of 0.0 or may be determined quarterly by careful chemical analysis of feed material and CKD material from each kiln using well documented analytical and calculational methods or the appropriate industry standard practice.

§ 98.85 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations in § 98.83 is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations. The owner or operator must document and keep records of the procedures used for all such estimates.

(a) If the CEMS approach is used to determine combined process and combustion CO_2 emissions, the missing data procedures in § 98.35 apply.

(b) For CO_2 process emissions from cement manufacturing facilities calculated according to § 98.83(d), if data on the carbonate content (of clinker or CKD), noncalcined content (of clinker or CKD) or the annual organic carbon content of raw materials are missing, facilities must undertake a new analysis.

(c) For each missing value of monthly clinker production the substitute data value must be the best available estimate of the monthly clinker production based on information used for accounting purposes, or use the maximum tons per day capacity of the system and the number of days per month.

(d) For each missing value of monthly raw material consumption the substitute data value must be the best available estimate of the monthly raw material consumption based on information used for accounting purposes (such as purchase records), or use the maximum tons per day raw material throughput of the kiln and the number of days per month.

§ 98.86 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) and (b) of this section, as appropriate.

(a) If a CEMS is used to measure CO_2 emissions, then you must report under this subpart the relevant information required by § 98.36(e)(2)(vi) and the information listed in this paragraph(a):

(1) Monthly clinker production from each kiln at the facility.

(2) Monthly cement production from each kiln at the facility.

(3) Number of kilns and number of operating kilns.

(b) If a CEMS is not used to measure CO_2 emissions, then you must report the information listed in this paragraph (b) for each kiln:

(1) Kiln identification number.

(2) Monthly clinker production from each kiln.

(3) Monthly cement production from each kiln.

(4) Number of kilns and number of operating kilns.

(5) Quarterly quantity of CKD not recycled to the kiln for each kiln at the facility.

(6) Monthly fraction of total CaO, total MgO, non-calcined CaO and non-calcined MgO in clinker for each kiln (as wt-fractions).

(7) Method used to determine non-calcined CaO and non-calcined MgO in clinker.

(8) Quarterly fraction of total CaO, total MgO, non-calcined CaO and non-calcined MgO in CKD not recycled to the kiln for each kiln (as wt-fractions).

(9) Method used to determine non-calcined CaO and non-calcined MgO in CKD.

(10) Monthly kiln-specific clinker CO_2 emission factors for each kiln (metric tons CO_2/metric ton clinker produced).

(11) Quarterly kiln-specific CKD CO_2 emission factors for each kiln (metric tons CO_2/metric ton CKD produced).

(12) Annual organic carbon content of each raw material (wt-fraction, dry basis).

(13) Annual consumption of each raw material (dry basis).

(14) Number of times missing data procedures were used to determine the following information:

(i) Clinker production (number of months).

(ii) Carbonate contents of clinker (number of months).

(iii) Non-calcined content of clinker (number of months).

(iv) CKD not recycled to kiln (number of quarters).

(v) Non-calcined content of CKD (number of quarters)

(vi) Organic carbon contents of raw materials (number of times).

(vii) Raw material consumption (number of months).

§ 98.87 Records that must be retained.

(a) If a CEMS is used to measure CO_2 emissions, then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in § 98.37.

(1) Documentation of monthly calculated kiln-specific clinker CO_2 emission factor.

(2) Documentation of quarterly calculated kiln-specific CKD CO_2 emission factor.

(3) Measurements, records and calculations used to determine reported parameters.

(b) If a CEMS is not used to measure CO_2 emissions, then in addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) through (b) of this section for each portland cement manufacturing facility.

§ 98.88 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart I—[Reserved]

Subpart J—[Reserved]

Subpart K—Ferroalloy Production

§ 98.110 Definition of the source category.

The ferroalloy production source category consists of any facility that uses pyrometallurgical techniques to produce any of the following metals: ferrochromium, ferromanganese, ferromolybdenum, ferronickel, ferrosilicon, ferrotitanium, ferrotungsten, ferrovanadium, silicomanganese, or silicon metal.

§ 98.111 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a ferroalloy production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.112 GHGs to report.

You must report:

(a) Process CO_2 emissions from each electric arc furnace (EAF) used for the production of any ferroalloy listed in § 98.110.

(b) CO_2, CH_4, and N_2O emissions from each stationary combustion unit following the requirements of subpart C of this part. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources).

§ 98.113 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each EAF using the procedures in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the process CO_2 emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the annual process CO_2 emissions using the procedure in either paragraph (b)(1) or (b)(2) of this section.

(1) Calculate and report under this subpart the annual process CO_2 emissions from EAFs by operating and maintaining a CEMS according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and the applicable requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(2) Calculate and report under this subpart the annual process CO_2 emissions from the EAFs using the carbon mass balance procedure specified in paragraphs (b)(2)(i) and (b)(2)(ii) of this section.

(i) For each EAF, determine the annual mass of carbon in each carbon-containing input and output material for the EAF and estimate annual process CO_2 emissions from the EAF using Equation K–1 of this section. Carbon-containing input materials include carbon electrodes and carbonaceous reducing agents. If you document that a specific input or output material contributes less than 1 percent of the total carbon into or out of the process, you do not have to include the material in your calculation using Equation K–1 of this section.

$$
\begin{aligned}
E_{CO2} = {} & \frac{44}{12} \times \frac{2000}{2205} \times \sum_{1}^{i} \left(M_{reducing\ agent_i} \times C_{reducing\ agent_i} \right) \\
& + \frac{44}{12} \times \frac{2000}{2205} \times \sum_{1}^{m} \left(M_{electrode_m} \times C_{electrode_m} \right) \\
& + \frac{44}{12} \times \frac{2000}{2205} \times \sum_{1}^{h} \left(M_{ore_h} \times C_{ore_h} \right) \\
& + \frac{44}{12} \times \frac{2000}{2205} \times \sum_{1}^{j} \left(M_{\mathrm{flux}_j} \times C_{\mathrm{flux}_j} \right) \\
& - \frac{44}{12} \times \frac{2000}{2205} \times \sum_{1}^{k} \left(M_{product\ outgoing_k} \times C_{product\ outgoing_k} \right) \\
& - \frac{44}{12} \times \frac{2000}{2205} \times \sum_{1}^{l} \left(M_{non\text{-}product\ outgoing_l} \times C_{non\text{-}product\ outgoing_l} \right)
\end{aligned}
\qquad \text{(Eq. K-1)}
$$

Where:

E_{CO2} = Annual process CO_2 emissions from an individual EAF (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

2000/2205 = Conversion factor to convert tons to metric tons.

$M_{reducing\ agent_i}$ = Annual mass of reducing agent *i* fed, charged, or otherwise introduced into the EAF (tons).

$C_{reducing\ agent_i}$ = Carbon content in reducing agent *i* (percent by weight, expressed as a decimal fraction).

$M_{electrode_m}$ = Annual mass of carbon electrode *m* consumed in the EAF (tons).

$C_{electrode_m}$ = Carbon content of the carbon electrode *m* (percent by weight, expressed as a decimal fraction).

M_{ore_h} = Annual mass of ore *h* charged to the EAF (tons).

C_{ore_h} = Carbon content in ore *h* (percent by weight, expressed as a decimal fraction).

M_{flux_j} = Annual mass of flux material *j* fed, charged, or otherwise introduced into the EAF to facilitate slag formation (tons).

C_{flux_j} = Carbon content in flux material *j* (percent by weight, expressed as a decimal fraction).

$M_{product_k}$ = Annual mass of alloy product *k* tapped from EAF (tons).

$C_{product_k}$ = Carbon content in alloy product *k*. (percent by weight, expressed as a decimal fraction).

$M_{non\text{-}product\ outgoing_l}$ = Annual mass of non-product outgoing material *l* removed from EAF (tons).

$C_{non\text{-}product\ outgoing_l}$ = Carbon content in non-product outgoing material *l* (percent by weight, expressed as a decimal fraction).

(ii) Determine the combined annual process CO_2 emissions from the EAFs at your facility using Equation K–2 of this section.

$$CO_2 = \sum_{1}^{k} E_{CO2_k} \qquad \text{(Eq. K-2)}$$

Where:

CO_2 = Annual process CO_2 emissions from EAFs at facility used for the production of any ferroalloy listed in § 98.110 (metric tons).

E_{CO2_k} = Annual process CO_2 emissions calculated from EAF *k* calculated using Equation K–1 of this section (metric tons).

k = Total number of EAFs at facility used for the production of any ferroalloy listed in § 98.110.

(c) If GHG emissions from an EAF are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

(d) For the EAFs at your facility used for the production of any ferroalloy listed in Table K–1 of this subpart, you must calculate and report the annual CH_4 emissions using the procedure specified in paragraphs (d)(1) and (2) of this section.

(1) For each EAF, determine the annual CH_4 emissions using Equation K–3 of this section.

$$E_{CH4} = \sum_{1}^{i} \left(M_{product_i} \times \frac{2000}{2205} \times EF_{product_i} \right) \qquad \text{(Eq. K-3)}$$

Where:

E_{CH4} = Annual process CH_4 emissions from an individual EAF (metric tons).

$M_{product_i}$ = Annual mass of alloy product *i* produced in the EAF (tons).

2000/2205 = Conversion factor to convert tons to metric tons.

$EF_{product_i}$ = CH_4 emission factor for alloy product *i* from Table K–1 in this subpart (kg of CH_4 emissions per metric ton of alloy product *i*).

(2) Determine the combined process CH_4 emissions from the EAFs at your facility using Equation K–4 of this section:

$$CH_4 = \sum_{1}^{j} E_{CH4_j} \qquad \text{(Eq. K-4)}$$

Where:

CH_4 = Annual process CH_4 emissions from EAFs at facility used for the production of ferroalloys listed in Table K–1 of this subpart (metric tons).

E_{CH4_j} = Annual process CH_4 emissions from EAF *j* calculated using Equation K–3 of this section (metric tons).

j = Total number of EAFs at facility used for the production of ferroalloys listed in Table K–1 of this subpart.

§ 98.114 Monitoring and QA/QC requirements.

If you determine annual process CO_2 emissions using the carbon mass balance procedure in § 98.113(b)(2), you must meet the requirements specified in paragraphs (a) and (b) of this section.

(a) Determine the annual mass for each material used for the calculations of annual process CO_2 emissions using Equation K–1 of this subpart by summing the monthly mass for the material determined for each month of the calendar year. The monthly mass may be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of the material placed in the unit or by calculations using process operating information.

(b) For each material identified in paragraph (a) of this section, you must determine the average carbon content of the material consumed, used, or produced in the calendar year using the methods specified in either paragraph (b)(1) or (b)(2) of this section. If you document that a specific process input or output contributes less than one percent of the total mass of carbon into or out of the process, you do not have to determine the monthly mass or annual carbon content of that input or output.

(1) Information provided by your material supplier.

(2) Collecting and analyzing at least three representative samples of the material inputs and outputs each year. The carbon content of the material must be analyzed at least annually using the standard methods (and their QA/QC procedures) specified in paragraphs (b)(2)(i) through (b)(2)(iii) of this section, as applicable.

(i) ASTM E1941–04, Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys (incorporated by reference, *see* § 98.7) for analysis of metal ore and alloy product.

(ii) ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, *see* § 98.7), for analysis of carbonaceous reducing agents and carbon electrodes.

(iii) ASTM C25–06, Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime (incorporated by reference, *see* § 98.7) for analysis of flux materials such as limestone or dolomite.

§ 98.115 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations in § 98.113 is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) If you determine CO_2 emissions for the EAFs at your facility using the carbon mass balance procedure in § 98.113(b), 100 percent data availability is required for the carbon content of the input and output materials. You must repeat the test for average carbon contents of inputs according to the procedures in § 98.114(b) if data are missing.

(b) For missing records of the monthly mass of carbon-containing inputs and outputs, the substitute data value must be based on the best available estimate of the mass of the inputs and outputs from on all available process data or data used for accounting purposes, such as purchase records.

(c) If you are required to calculate CH_4 emissions for an EAF at your facility as specified in § 98.113(d), the estimate is based an annual quantity of certain alloy products, so 100 percent data availability is required.

§ 98.116 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) through (e) of this section, as applicable:

(a) Annual facility ferroalloy product production capacity (tons).

(b) Annual production for each ferroalloy product (tons) identified in § 98.110, as applicable.

(c) Total number of EAFs at facility used for production of ferroalloy products reported in paragraph (a)(4) of this section.

(d) If a CEMS is used to measure CO_2 emissions, then you must report under this subpart the relevant information required by § 98.37 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (d)(1) through (d)(3) of this section.

(1) Annual process CO_2 emissions (in metric tons) from each EAF used for the production of any ferroalloy listed in Table K–1 of this subpart (metric tons).

(2) Annual process CH_4 emissions (in metric tons) from each EAF used for the production of any ferroalloy listed in Table K–1 of this subpart (metric tons).

(3) Identification number of each EAF.

(e) If a CEMS is not used to measure CO_2 process emissions, and the carbon mass balance procedure is used to determine CO_2 emissions according to the requirements in § 98.113(b), then you must report the following information specified in paragraphs (e)(1) through (e)(7) of this section.

(1) Annual process CO_2 emissions (in metric tons) from each EAF used for the production of any ferroalloy listed in Table K–1 of this subpart (metric tons).

(3) Identification number for each material.

(4) Annual material quantity for each material included for the calculation of annual process CO_2 emissions for each EAF.

(5) Annual average of the carbon content determinations for each material included for the calculation of annual process CO_2 emissions for each EAF (percent by weight, expressed as a decimal fraction).

(6) List the method used for the determination of carbon content for each material reported in paragraph (e)(5) of this section (e.g., supplier provided information, analyses of representative samples you collected).

(7) If you use the missing data procedures in § 98.115(b), you must report how monthly mass of carbon-containing inputs and outputs with missing data was determined and the number of months the missing data procedures were used.

§ 98.117 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) through (d) of this section for each EAF, as applicable.

(a) If a CEMS is used to measure CO_2 emissions according to the requirements in § 98.113(a), then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in § 98.37 and the information specified in paragraphs (a)(1) through (a)(3) of this section.

(1) Monthly EAF production quantity for each ferroalloy product (tons).

(2) Number of EAF operating hours each month.

(3) Number of EAF operating hours in a calendar year.

(b) If the carbon mass balance procedure is used to determine CO_2 emissions according to the requirements in § 98.113(b)(2), then you must retain records for the information specified in paragraphs (b)(1) through (b)(5) of this section.

(1) Monthly EAF production quantity for each ferroalloy product (tons).

(2) Number of EAF operating hours each month.

(3) Number of EAF operating hours in a calendar year.

(4) Monthly material quantity consumed, used, or produced for each material included for the calculations of annual process CO_2 emissions (tons).

(5) Average carbon content determined and records of the supplier provided information or analyses used for the determination for each material included for the calculations of annual process CO_2 emissions.

(c) You must keep records that include a detailed explanation of how company records of measurements are used to estimate the carbon input and output to each EAF, including documentation of specific input or output materials excluded from Equation K–1 of this subpart that contribute less than 1 percent of the total carbon into or out of the process. You also must document the procedures used to ensure the accuracy of the measurements of materials fed, charged, or placed in an EAF including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

(d) If you are required to calculate CH_4 emissions for the EAF as specified in § 98.113(d), you must maintain records of the total amount of each alloy product produced for the specified reporting period, and the appropriate alloy-product specific emission factor used to calculate the CH_4 emissions.

§ 98.118 Definitions.

All terms used of this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE K–1 TO SUBPART K OF PART 98—ELECTRIC ARC FURNACE (EAF) CH_4 EMISSION FACTORS

Alloy product produced in EAF	CH_4 emission factor (kg CH_4 per metric ton product)		
	EAF Operation		
	Batch-charging	Sprinkle-charging [a]	Sprinkle-charging and >750 °C [b]
Silicon metal	1.5	1.2	0.7
Ferrosilicon 90%	1.4	1.1	0.6
Ferrosilicon 75%	1.3	1.0	0.5
Ferrosilicon 65%	1.3	1.0	0.5

[a] Sprinkle-charging is charging intermittently every minute.
[b] Temperature measured in off-gas channel downstream of the furnace hood.

Subpart L—[Reserved]

Subpart M—[Reserved]

Subpart N—Glass Production

§ 98.140 Definition of the source category.

(a) A glass manufacturing facility manufactures flat glass, container glass, pressed and blown glass, or wool fiberglass by melting a mixture of raw materials to produce molten glass and form the molten glass into sheets, containers, fibers, or other shapes. A glass manufacturing facility uses one or more continuous glass melting furnaces to produce glass.

(b) A glass melting furnace that is an experimental furnace or a research and development process unit is not subject to this subpart.

§ 98.141 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a glass production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.142 GHGs to report.

You must report:

(a) CO_2 process emissions from each continuous glass melting furnace.

(b) CO_2 combustion emissions from each continuous glass melting furnace.

(c) CH_4 and N_2O combustion emissions from each continuous glass melting furnace. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) CO_2, CH_4, and N_2O emissions from each stationary fuel combustion unit other than continuous glass melting furnaces. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§ 98.143 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each continuous glass melting furnace using the procedure in paragraphs (a) and (b) of this section.

(a) For each continuous glass melting furnace that meets the conditions specified in § 98.33(b)(4)(ii) or (iii), you must calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For each continuous glass melting furnace that is not subject to the requirements in paragraph (a) of this section, calculate and report the process and combustion CO_2 emissions from the glass melting furnace by using either the procedure in paragraph (b)(1) of this section or the procedure in paragraphs (b)(2) through (b)(7) of this section, except as specified in paragraph (c) of this section.

(1) Calculate and report under this subpart the combined process and combustion CO_2 emissions by operating

and maintaining a CEMS to measure CO_2 emissions according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(2) Calculate and report the process and combustion CO_2 emissions separately using the procedures specified in paragraphs (b)(2)(i) through (b)(2)(vi) of this section.

(i) For each carbonate-based raw material charged to the furnace, obtain from the supplier of the raw material the carbonate-based mineral mass fraction.

(ii) Determine the quantity of each carbonate-based raw material charged to the furnace.

(iii) Apply the appropriate emission factor for each carbonate-based raw material charged to the furnace, as shown in Table N–1 to this subpart.

(iv) Use Equation N–1 of this section to calculate process mass emissions of CO_2 for each furnace:

$$E_{CO2} = \sum_{i=1}^{n} MF_i \bullet \left(M_i \bullet \frac{2000}{2205} \right) \bullet EF_i \bullet F_i \qquad \text{(Eq. N-1)}$$

Where:

E_{CO2} = Process emissions of CO_2 from the furnace (metric tons).

n = Number of carbonate-based raw materials charged to furnace.

MF_i = Annual average mass fraction of carbonate-based mineral i in carbonate-based raw material i (percentage, expressed as a decimal).

M_i = Annual amount of carbonate-based raw material i charged to furnace (tons).

2000/2205 = Conversion factor to convert tons to metric tons.

EF_i = Emission factor for carbonate-based raw material i (metric ton CO_2 per metric ton carbonate-based raw material as shown in Table N–1 to this subpart).

F_i = Fraction of calcination achieved for carbonate-based raw material i, assumed to be equal to 1.0 (percentage, expressed as a decimal).

(v) You must calculate the total process CO_2 emissions from continuous glass melting furnaces at the facility using Equation N–2 of this section:

$$CO_2 = \sum_{i=1}^{k} E_{CO_2 i} \qquad \text{(Eq. N-2)}$$

Where:

CO_2 = Annual process CO_2 emissions from glass manufacturing facility (metric tons).

E_{CO2i} = Annual CO_2 emissions from glass melting furnace i (metric tons).

k = Number of continuous glass melting furnaces.

(vi) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion CO_2 emissions in the glass furnace according to the applicable requirements in subpart C.

(c) As an alternative to data provided by the raw material supplier, a value of 1.0 can be used for the mass fraction (MF_i) of carbonate-based mineral i in Equation N–1 of this section.

§ 98.144 Monitoring and QA/QC requirements.

(a) You must measure annual amounts of carbonate-based raw materials charged to each continuous glass melting furnace from monthly measurements using plant instruments used for accounting purposes, such as calibrated scales or weigh hoppers. Total annual mass charged to glass melting furnaces at the facility shall be compared to records of raw material purchases for the year.

(b) You must measure carbonate-based mineral mass fractions at least annually to verify the mass fraction data provided by the supplier of the raw material; such measurements shall be based on sampling and chemical analysis conducted by a certified laboratory using ASTM D3682–01 (Reapproved 2006) Standard Test Method for Major and Minor Elements in Combustion Residues from Coal Utilization Processes (incorporated by reference, see § 98.7).

(c) You must determine the annual average mass fraction for the carbonate-based mineral in each carbonate-based raw material by calculating an arithmetic average of the monthly data obtained from raw material suppliers or sampling and chemical analysis.

(d) You must determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis using an industry consensus standard. This chemical analysis must be conducted using an x-ray fluorescence test or other enhanced testing method published by an industry consensus standards organization (e.g., ASTM, ASME, API, etc.).

§ 98.145 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., carbonate raw materials consumed, etc.). If the monitoring and quality assurance procedures in § 98.144 cannot be followed and data is missing, you must use the most appropriate of the missing data procedures in paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such missing value estimates.

(a) For missing data on the monthly amounts of carbonate-based raw materials charged to any continuous glass melting furnace use the best available estimate(s) of the parameter(s), based on all available process data or data used for accounting purposes, such as purchase records.

(b) For missing data on the mass fractions of carbonate-based minerals in the carbonate-based raw materials assume that the mass fraction of each carbonate based mineral is 1.0.

§ 98.146 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) and (b) of this section, as applicable.

(a) If a CEMS is used to measure CO_2 emissions, then you must report under this subpart the relevant information required under § 98.37 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (a)(1) and (a)(2) of this section:

(1) Annual quantity of each carbonate-based raw material charged to each continuous glass melting furnace and for all furnaces combined (tons).

(2) Annual quantity of glass produced (tons).

(b) If a CEMS is not used to determine CO_2 emissions from continuous glass melting furnaces, and process CO_2 emissions are calculated according to the procedures specified in § 98.143(b), then you must report the following information as specified in paragraphs (b)(1) through (b)(9) of this section:

(1) Annual process emissions of CO_2 (metric tons) for each continuous glass melting furnace and for all furnaces combined.

(2) Annual quantity of each carbonate-based raw material charged (tons) to each continuous glass melting furnace and for all furnaces combined.

(3) Annual quantity of glass produced (tons) from each continuous glass melting furnace and from all furnaces combined.

(4) Carbonate-based mineral mass fraction (percentage, expressed as a decimal) for each carbonate-based raw material charged to a continuous glass melting furnace.

(5) Results of all tests used to verify the carbonate-based mineral mass fraction for each carbonate-based raw material charged to a continuous glass melting furnace, as specified in paragraphs (b)(5)(i) through (b)(5)(iii) of this section.

(i) Date of test.

(ii) Method(s) and any variations used in the analyses.

(iii) Mass fraction of each sample analyzed.

(6) The fraction of calcination achieved for each carbonate-based raw material, if a value other than 1.0 is used to calculate process mass emissions of CO_2.

(7) Method used to determine fraction of calcination (percentage, expressed as a decimal).

(8) Total number of continuous glass melting furnaces.

(9) The number of times in the reporting year that missing data procedures were followed to measure monthly quantities of carbonate-based raw materials any continuous glass melting furnace or mass fraction of the carbonate-based minerals (months).

§ 98.147 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the records listed in paragraphs (a), (b), and (c) of this section.

(a) If a CEMS is used to measure emissions, then you must retain the records required under § 98.37 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (a)(1) and (a)(2) of this section:

(1) Monthly glass production rate for each continuous glass melting furnace (tons).

(2) Monthly amount of each carbonate-based raw material charged to each continuous glass melting furnace (tons).

(b) If process CO_2 emissions are calculated according to the procedures specified in § 98.143(b), you must retain the records in paragraphs (b)(1) through (b)(5) of this section.

(1) Monthly glass production rate for each continuous glass melting furnace (metric tons).

(2) Monthly amount of each carbonate-based raw material charged to each continuous glass melting furnace (metric tons).

(3) Data on carbonate-based mineral mass fractions provided by the raw material supplier for all raw materials consumed annually and included in calculating process emissions in Equation N–1 of this subpart.

(4) Results of all tests used to verify the carbonate-based mineral mass fraction for each carbonate-based raw material charged to a continuous glass melting furnace, including the data specified in paragraphs (b)(4)(i) through (b)(4)(v) of this section.

(i) Date of test.

(ii) Method(s), and any variations of the methods, used in the analyses.

(iii) Mass fraction of each sample analyzed.

(iv) Relevant calibration data for the instrument(s) used in the analyses.

(v) Name and address of laboratory that conducted the tests.

(5) The fraction of calcination achieved for each carbonate-based raw material (percentage, expressed as a decimal), if a value other than 1.0 is used to calculate process mass emissions of CO_2.

(c) All other documentation used to support the reported GHG emissions.

§ 98.148 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE N–1 TO SUBPART N OF PART 98—CO_2 EMISSION FACTORS FOR CARBONATE-BASED RAW MATERIALS

Carbonate-based raw material—mineral	CO_2 emission factor [a]
Limestone—$CaCO_3$	0.440
Dolomite—$CaMg(CO_3)_2$	0.477
Sodium carbonate/soda ash—Na_2CO_3	0.415

[a] Emission factors in units of metric tons of CO_2 emitted per metric ton of carbonate-based raw material charged to the furnace.

Subpart O—HCFC–22 Production and HFC–23 Destruction

§ 98.150 Definition of the source category.

The HCFC–22 production and HFC–23 destruction source category consists of HCFC–22 production processes and HFC–23 destruction processes.

(a) An HCFC–22 production process produces HCFC–22 (chlorodifluoromethane, or $CHClF_2$) from chloroform ($CHCl_3$) and hydrogen fluoride (HF).

(b) An HFC–23 destruction process is any process in which HFC–23 undergoes destruction. An HFC–23 destruction process may or may not be co-located with an HCFC–22 production process at the same facility.

§ 98.151 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an HCFC–22 production or HFC–23 destruction process and the facility meets the requirements of either § 98.2(a)(1) or (a)(2).

§ 98.152 GHGs to report.

(a) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary combustion unit following the requirements of subpart C.

(b) You must report HFC–23 emissions from HCFC–22 production processes and HFC–23 destruction processes.

§ 98.153 Calculating GHG emissions.

(a) The mass of HFC–23 generated from each HCFC–22 production process shall be estimated by using one of two methods, as applicable:

(1) Where the mass flow of the combined stream of HFC–23 and another reaction product (e.g., HCl) is measured, multiply the weekly (or more frequent) HFC–23 concentration measurement (which may be the average of more frequent concentration measurements) by the weekly (or more frequent) mass flow of the combined stream of HFC–23 and the other product. To estimate annual HFC–23 production, sum the weekly (or more frequent) estimates of the quantities of HFC–23 produced over the year. This calculation is summarized in Equation O–1 of this section:

$$G_{23} = \sum_{p=1}^{n} c_{23} * F_p * 10^{-3} \qquad \text{(Eq. O-1)}$$

Where:

G_{23} = Mass of HFC–23 generated annually (metric tons).

c_{23} = Fraction HFC–23 by weight in HFC–23/other product stream.

F_p = Mass flow of HFC–23/other product stream during the period p (kg).

p = Period over which mass flows and concentrations are measured.

n = Number of concentration and flow measurement periods for the year.

10^{-3} = Conversion factor from kilograms to metric tons.

(2) Where the mass of only a reaction product other than HFC–23 (either HCFC–22 or HCl) is measured, multiply the ratio of the weekly (or more frequent) measurement of the HFC–23 concentration and the weekly (or more frequent) measurement of the other product concentration by the weekly (or more frequent) mass produced of the other product. To estimate annual HFC–23 production, sum the weekly (or more

frequent) estimates of the quantities of HFC–23 produced over the year. This calculation is summarized in Equation O–2 of this section, assuming that the other product is HCFC–22. If the other product is HCl, HCl may be substituted for HCFC–22 in Equations O–2 and O–3 of this section.

$$G_{23} = \sum_{p=1}^{n} \left(\frac{c_{23}}{c_{22}} \right) * P_{22} * 10^{-3} \qquad \text{(Eq. O-2)}$$

Where:

G_{23} = Mass of HFC–23 generated annually (metric tons).
c_{23} = Fraction HFC–23 by weight in HCFC–22/HFC–23 stream.
c_{22} = Fraction HCFC–22 by weight in HCFC–22/HFC–23 stream.
P_{22} = Mass of HCFC–22 produced over the period p (kg), calculated using Equation O–3 of this section.
p = Period over which masses and concentrations are measured.
n = Number of concentration and mass measurement periods for the year.
10^{-3} = Conversion factor from kilograms to metric tons.

(b) The mass of HCFC–22 produced over the period p shall be estimated by using Equation O–3 of this section:

$$P_{22} = LF * \left(O_{22} - U_{22} \right) \qquad \text{(Eq. O-3)}$$

Where:

P_{22} = Mass of HCFC–22 produced over the period p (kg).
O_{22} = mass of HCFC–22 that is measured coming out of the Production process over the period p (kg).
U_{22} = Mass of used HCFC–22 that is added to the production process upstream of the output measurement over the period p (kg).
LF = Factor to account for the loss of HCFC–22 upstream of the measurement. The value for LF shall be determined pursuant to § 98.154(e).

(c) For HCFC–22 production facilities that do not use a thermal oxidizer or that have a thermal oxidizer that is not directly connected to the HCFC–22 production equipment, HFC–23 emissions shall be estimated using Equation O–4 of this section:

$$E_{23} = G_{23} - \left(S_{23} + OD_{23} + D_{23} + I_{23} \right) \qquad \text{(Eq. O-4)}$$

Where:

E_{23} = Mass of HFC–23 emitted annually (metric tons).
G_{23} = Mass of HFC–23 generated annually (metric tons).
S_{23} = Mass of HFC–23 sent off site for sale annually (metric tons).
OD_{23} = Mass of HFC–23 sent off site for destruction (metric tons).
D_{23} = Mass of HFC–23 destroyed on site (metric tons).
I_{23} = Increase in HFC–23 inventory = HFC–23 in storage at end of year—HFC–23 in storage at beginning of year (metric tons).

(d) For HCFC–22 production facilities that use a thermal oxidizer connected to the HCFC–22 production equipment, HFC–23 emissions shall be estimated using Equation O–5 of this section:

$$E_{23} = E_L + E_{PV} + E_D \qquad \text{(Eq. O-5)}$$

Where:

E_{23} = Mass of HFC–23 emitted annually (metric tons).
E_L = Mass of HFC–23 emitted annually from equipment leaks, calculated using Equation O–6 of this section (metric tons).
E_{PV} = Mass of HFC–23 emitted annually from process vents, calculated using Equation O–7 of this section (metric tons).
E_D = Mass of HFC–23 emitted annually from thermal oxidizer (metric tons), calculated using Equation O–8 of this section.

(1) The mass of HFC–23 emitted annually from equipment leaks (for use in Equation O–5 of this section) shall be estimated by using Equation O–6 of this section:

$$E_L = \sum_{p=1}^{n} \sum_{t} c_{23} * \left(F_{Gt} * N_{Gt} + F_{Lt} * N_{Lt} \right) * 10^{-3} \qquad \text{(Eq. O-6)}$$

Where:

E_L = Mass of HFC–23 emitted annually from equipment leaks (metric tons).
c_{23} = Fraction HFC–23 by weight in the stream(s) in the equipment.
F_{Gt} = The applicable leak rate specified in Table O–1 of this subpart for each source of equipment type and service t with a screening value greater than or equal to 10,000 ppmv (kg/hr/source).
N_{Gt} = The number of sources of equipment type and service t with screening values greater than or equal to 10,000 ppmv as determined according to § 98.154(i).
F_{Lt} = The applicable leak rate specified in Table O–1 of this subpart for each source of equipment type and service t with a screening value of less than 10,000 ppmv (kg/hr/source).
N_{Lt} = The number of sources of equipment type and service t with screening values less than 10,000 ppmv as determined according to § 98.154(j).
p = One hour.
n = Number of hours during the year during which equipment contained HFC–23.
t = Equipment type and service as specified in Table O–1 of this subpart .
10^{-3} = Factor converting kg to metric tons.

(2) The mass of HFC–23 emitted annually from process vents (for use in Equation O–5 of this section) shall be estimated by using Equation O–7 of this section:

$$E_{PV} = \sum_{p=1}^{n} ER_T * \left(\frac{PR_p}{PR_T} \right) * l_p * 10^{-3} \qquad \text{(Eq. O-7)}$$

Where:

E_{PV} = Mass of HFC–23 emitted annually from process vents (metric tons).
ER_T = The HFC–23 emission rate from the process vents during the period of the most recent test (kg/hr).
PR_p = The HCFC–22 production rate during the period p (kg/hr).
PR_T = The HCFC–22 production rate during the most recent test period (kg/hr).
l_p = The length of the period p (hours).
10^{-3} = Factor converting kg to metric tons.
n = The number of periods in a year.

(3) The total mass of HFC–23 emitted from destruction devices shall be estimated by using Equation O–8 of this section:

$$E_D = F_D - D_{23} \qquad \text{(Eq. O-8)}$$

Where:

E_D = Mass of HFC–23 emitted annually from the destruction device (metric tons).

F_D = Mass of HFC–23 fed into the destruction device annually (metric tons).

D_{23} = Mass of HFC–23 destroyed annually (metric tons).

(4) For facilities that destroy HFC–23, the total mass of HFC–23 destroyed shall be estimated by using Equation O–9 of this section:

$$D_{23} = F_D * DE \qquad \text{(Eq. O-9)}$$

Where:

D_{23} = Mass of HFC–23 destroyed annually (metric tons).

F_D = Mass of HFC–23 fed into the destruction device annually (metric tons).

DE = Destruction Efficiency of the destruction device (fraction).

§ 98.154 Monitoring and QA/QC requirements.

These requirements apply to measurements that are reported under this subpart or that are used to estimate reported quantities pursuant to § 98.153.

(a) The concentrations (fractions by weight) of HFC–23 and HCFC–22 in the product stream shall be measured at least weekly using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples.

(b) The mass flow of the product stream containing the HFC–23 shall be measured at least weekly using weigh scales, flowmeters, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(c) The mass of HCFC–22 or HCl coming out of the production process shall be measured at least weekly using weigh scales, flowmeters, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(d) The mass of any used HCFC–22 added back into the production process upstream of the output measurement in paragraph (c) of this section shall be measured (when being added) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better. If the mass in paragraph (c) of this section is measured by weighing containers that include returned heels as well as newly produced fluorinated GHGs, the returned heels shall be considered used fluorinated HCFC–22 for purposes of this paragraph (d) of this section and § 98.153(b).

(e) The loss factor LF in Equation O–3 of this subpart for the mass of HCFC–22 produced shall have the value 1.015 or another value that can be demonstrated, to the satisfaction of the Administrator, to account for losses of HCFC–22 between the reactor and the point of measurement at the facility where production is being estimated.

(f) The mass of HFC–23 sent off site for sale shall be measured at least weekly (when being packaged) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(g) The mass of HFC–23 sent off site for destruction shall be measured at least weekly (when being packaged) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than HFC–23, the concentration of the fluorinated GHG shall be measured at least weekly using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the HFC–23 sent to another facility for destruction.

(h) The masses of HFC–23 in storage at the beginning and end of the year shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(i) The number of sources of equipment type t with screening values greater than or equal to 10,000 ppmv shall be determined using EPA Method 21 at 40 CFR part 60, appendix A–7, and defining a leak as follows:

(1) A leak source that could emit HFC–23, and

(2) A leak source at whose surface a concentration of fluorocarbons equal to or greater than 10,000 ppm is measured.

(j) The number of sources of equipment type t with screening values less than 10,000 ppmv shall be the difference between the number of leak sources of equipment type t that could emit HFC–23 and the number of sources of equipment type t with screening values greater than or equal to 10,000 ppmv as determined under paragraph (h) of this section.

(k) The mass of HFC–23 emitted from process vents shall be estimated at least monthly by incorporating the results of the most recent emissions test into Equation O–6 of this subpart. HCFC–22 production facilities that use a thermal oxidizer connected to the HCFC–22 production equipment shall conduct emissions tests at process vents at least once every five years or after significant changes to the process. Emissions tests shall be conducted in accordance with EPA Method 18 at 40 CFR part 60, appendix A–6, under conditions that are typical for the production process at the facility. The sensitivity of the tests shall be sufficient to detect an emission rate that would result in annual emissions of 200 kg of HFC–23 if sustained over one year.

(l) For purposes of Equation O–9 of this subpart, the destruction efficiency must be equated to the destruction efficiency determined during a new or previous performance test of the destruction device. HFC–23 destruction facilities shall conduct annual measurements of HFC–23 concentrations at the outlet of the thermal oxidizer in accordance with EPA Method 18 at 40 CFR part 60, appendix A–6. Three samples shall be taken under conditions that are typical for the production process and destruction device at the facility, and the average concentration of HFC–23 shall be determined. The sensitivity of the concentration measurement shall be sufficient to detect an outlet concentration equal to or less than the outlet concentration determined in the destruction efficiency performance test. If the concentration measurement indicates that the HFC–23 concentration is less than or equal to that measured during the performance test that is the basis for the destruction efficiency, continue to use the previously determined destruction efficiency. If the concentration measurement indicates that the HFC–23 concentration is greater than that measured during the performance test that is the basis for the destruction efficiency, facilities shall either:

(1) Substitute the higher HFC–23 concentration for that measured during the destruction efficiency performance test and calculate a new destruction efficiency, or

(2) Estimate the mass emissions of HFC–23 from the destruction device based on the measured HFC–23 concentration and volumetric flow rate determined by measurement of volumetric flow rate using EPA Method 2, 2A, 2C,2D, or 2F at 40 CFR part 60, appendix A–1, or Method 26 at 40 CFR part 60, appendix A–2. Determine the mass rate of HFC–23 into the destruction device by measuring the HFC–23 concentration and volumetric flow rate at the inlet or by a metering device for HFC–23 sent to the device. Determine a new destruction efficiency

based on the mass flow rate of HFC–23 into and out of the destruction device.

(m) HCFC–22 production facilities shall account for HFC–23 generation and emissions that occur as a result of startups, shutdowns, and malfunctions, either recording HFC–23 generation and emissions during these events, or documenting that these events do not result in significant HFC–23 generation and/or emissions.

(n) The mass of HFC–23 fed into the destruction device shall be measured at least weekly using flow meters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than HFC–23, the concentrations of the HFC–23 shall be measured at least weekly using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the HFC–23 destroyed.

(o) In their estimates of the mass of HFC–23 destroyed, HFC–23 destruction facilities shall account for any temporary reductions in the destruction efficiency that result from any startups, shutdowns, or malfunctions of the destruction device, including departures from the operating conditions defined in state or local permitting requirements and/or oxidizer manufacturer specifications.

(p) Calibrate all flow meters, weigh scales, and combinations of volumetric and density measures using NIST-traceable standards and suitable methods published by a consensus standards organization (e.g., ASTM, ASME, ISO, or others). Recalibrate all flow meters, weigh scales, and combinations of volumetric and density measures at the minimum frequency specified by the manufacturer.

(q) All gas chromatographs used to determine the concentration of HFC–23 in process streams shall be calibrated at least monthly through analysis of certified standards (or of calibration gases prepared from a high-concentration certified standard using a gas dilution system that meets the requirements specified in Method 205 at 40 CFR part 51, appendix M) with known HFC–23 concentrations that are in the same range (fractions by mass) as the process samples.

§ 98.155 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required process sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the following requirements:

(1) For each missing value of the HFC–23 or HCFC–22 concentration, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(2) For each missing value of the product stream mass flow or product mass, the substitute value of that parameter shall be a secondary product measurement where such a measurement is available. If that measurement is taken significantly downstream of the usual mass flow or mass measurement (e.g., at the shipping dock rather than near the reactor), the measurement shall be multiplied by 1.015 to compensate for losses. Where a secondary mass measurement is not available, the substitute value of the parameter shall be an estimate based on a related parameter. For example, if a flowmeter measuring the mass fed into a destruction device is rendered inoperable, then the mass fed into the destruction device may be estimated using the production rate and the previously observed relationship between the production rate and the mass flow rate into the destruction device.

§ 98.156 Data reporting requirements.

(a) In addition to the information required by § 98.3(c), the HCFC–22 production facility shall report the following information at the facility level:

(1) Annual mass of HCFC–22 produced in metric tons.

(2) Loss Factor used to account for the loss of HCFC– 22 upstream of the measurement.

(3) Annual mass of reactants fed into the process in metric tons of reactant.

(4) The mass (in metric tons) of materials other than HCFC–22 and HFC–23 (i.e., unreacted reactants, HCl and other by-products) that occur in more than trace concentrations and that are permanently removed from the process.

(5) The method for tracking startups, shutdowns, and malfunctions and HFC–23 generation/emissions during these events.

(6) The names and addresses of facilities to which any HFC–23 was sent for destruction, and the quantities of HFC–23 (metric tons) sent to each.

(7) Annual mass of the HFC–23 generated in metric tons.

(8) Annual mass of any HFC–23 sent off site for sale in metric tons.

(9) Annual mass of any HFC–23 sent off site for destruction in metric tons.

(10) Mass of HFC–23 in storage at the beginning and end of the year, in metric tons.

(11) Annual mass of HFC–23 emitted in metric tons.

(12) Annual mass of HFC–23 emitted from equipment leaks in metric tons.

(13) Annual mass of HFC–23 emitted from process vents in metric tons.

(b) In addition to the information required by § 98.3(c), facilities that destroy HFC–23 shall report the following for each HFC–23 destruction process:

(1) Annual mass of HFC–23 fed into the thermal oxidizer.

(2) Annual mass of HFC–23 destroyed.

(3) Annual mass of HFC–23 emitted from the thermal oxidizer.

(c) Each HFC–23 destruction facility shall report the results of the facility's annual HFC–23 concentration measurements at the outlet of the destruction device, including:

(1) Flow rate of HFC–23 being fed into the destruction device in kg/hr.

(2) Concentration (mass fraction) of HFC–23 at the outlet of the destruction device.

(3) Flow rate at the outlet of the destruction device in kg/hr.

(d) Emission rate calculated from paragraphs (c)(2) and (3) of this section in kg/hr.

(e) HFC–23 destruction facilities shall submit a one-time report including the following information for each the destruction process:

(1) Destruction efficiency (DE).

(2) The methods used to determine destruction efficiency.

(3) The methods used to record the mass of HFC–23 destroyed.

(4) The name of other relevant federal or state regulations that may apply to the destruction process.

(5) If any changes are made that affect HFC–23 destruction efficiency or the methods used to record volume destroyed, then these changes must be reflected in a revision to this report. The revised report must be submitted to EPA within 60 days of the change.

§ 98.157 Records that must be retained.

(a) In addition to the data required by § 98.3(g), HCFC–22 production facilities shall retain the following records:

(1) The data used to estimate HFC–23 emissions.

(2) Records documenting the initial and periodic calibration of the gas chromatographs, weigh scales, volumetric and density measurements, and flowmeters used to measure the quantities reported under this rule, including the industry standards or manufacturer directions used for calibration pursuant to § 98.154(p) and (q).

(b) In addition to the data required by § 98.3(g), the HFC–23 destruction facilities shall retain the following records:

(1) Records documenting their one-time and annual reports in § 98.156(b) through (d).

(2) Records documenting the initial and periodic calibration of the gas chromatographs, weigh scales, volumetric and density measurements, and flowmeters used to measure the quantities reported under this subpart, including the industry standard practice or manufacturer directions used for calibration pursuant to § 98.154(p) and (q).

§ 98.158 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE O–1 TO SUBPART O OF PART 98—EMISSION FACTORS FOR EQUIPMENT LEAKS

Equipment type	Service	Emission factor (kg/hr/source)	
		≥10,000 ppmv	<10,000 ppmv
Valves	Gas	0.0782	0.000131
Valves	Light liquid	0.0892	0.000165
Pump seals	Light liquid	0.243	0.00187
Compressor seals	Gas	1.608	0.0894
Pressure relief valves	Gas	1.691	0.0447
Connectors	All	0.113	0.0000810
Open-ended lines	All	0.01195	0.00150

Subpart P—Hydrogen Production

§ 98.160 Definition of the source category.

(a) A hydrogen production source category consists of facilities that produce hydrogen gas sold as a product to other entities.

(b) This source category comprises process units that produce hydrogen by reforming, gasification, oxidation, reaction, or other transformations of feedstocks.

(c) This source category includes merchant hydrogen production facilities located within a petroleum refinery if they are not owned by, or under the direct control of, the refinery owner and operator.

§ 98.161 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a hydrogen production process and the facility meets the requirements of either § 98.2(a)(1) or (a)(2).

§ 98.162 GHGs to report.

You must report:

(a) CO_2 process emissions from each hydrogen production process unit.

(b) CO_2, CH_4 and N_2O combustion emissions from each hydrogen production process unit. You must calculate and report these combustion emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(c) CO_2, CH_4, and N_2O emissions from each stationary combustion unit other than hydrogen production process units. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) For CO_2 collected and transferred off site, you must follow the requirements of subpart PP of this part.

§ 98.163 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each hydrogen production process unit using the procedures specified in either paragraph (a) or (b) of this section.

(a) *Continuous Emissions Montoring Systems (CEMS).* Calculate and report under this subpart the process CO_2 emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) *Fuel and feedstock material balance approach.* Calculate and report process CO_2 emissions as the sum of the annual emissions associated with each fuel and feedstock used for hydrogen production by following paragraphs (b)(1) through (b)(3) of this section.

(1) *Gaseous fuel and feedstock.* You must calculate the annual CO_2 process emissions from gaseous fuel and feedstock according to Equation P–1 of this section:

$$CO_2 = \left(\sum_{n=1}^{k} \frac{44}{12} * Fdstk_n * CC_n * \frac{MW}{MVC} \right) * 0.001 \qquad \text{(Eq. P-1)}$$

Where:

CO_2 = Annual CO_2 process emissions arising from fuel and feedstock consumption (metric tons/yr).

$Fdstk_n$ = Volume of the gaseous fuel and feedstock used in month n (scf (at standard conditions of 68 °F and atmospheric pressure) of fuel and feedstock).

CC_n = Average carbon content of the gaseous fuel and feedstock, from the results of one or more analyses for month n (kg carbon per kg of fuel and feedstock).

MW = Molecular weight of the gaseous fuel and feedstock (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).
k = Months in the year.
44/12 = Ratio of molecular weights, CO_2 to carbon. 0.001 = Conversion factor from kg to metric tons.

(2) *Liquid fuel and feedstock.* You must calculate the annual CO_2 process emissions from liquid fuel and feedstock according to Equation P–2 of this section:

$$CO_2 = \left(\sum_{n=1}^{k} \frac{44}{12} * Fdstk_n * CC_n \right) * 0.001 \qquad \text{(Eq. P-2)}$$

Where:
CO_2 = Annual CO_2 emissions arising from fuel and feedstock consumption (metric tons/yr).
$Fdstk_n$ = Volume of the liquid fuel and feedstock used in month n (gallons of fuel and feedstock).
CC_n = Average carbon content of the liquid fuel and feedstock, from the results of one or more analyses for month n (kg carbon per gallon of fuel and feedstock).
k = Months in the year.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to metric tons.

(3) *Solid fuel and feedstock.* You must calculate the annual CO_2 process emissions from solid fuel and feedstock according to Equation P–3 of this section:

$$CO_2 = \left(\sum_{n=1}^{k} \frac{44}{12} * Fdstk_n * CC_n \right) * 0.001 \qquad \text{(Eq. P-3)}$$

Where:
CO_2 = Annual CO_2 emissions from fuel and feedstock consumption in metric tons per month (metric tons/yr).
$Fdstk_n$ = Mass of solid fuel and feedstock used in month n (kg of fuel and feedstock).
CC_n = Average carbon content of the solid fuel and feedstock, from the results of one or more analyses for month n (kg carbon per kg of fuel and feedstock).
k = Months in the year.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to metric tons.

(c) If GHG emissions from a hydrogen production process unit are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

§ 98.164 Monitoring and QA/QC requirements.

The GHG emissions data for hydrogen production process units must be quality-assured as specified in paragraphs (a) or (b) of this section, as appropriate for each process unit:

(a) If a CEMS is used to measure GHG emissions, then the facility must comply with the monitoring and QA/QC procedures specified in § 98.34(c).

(b) If a CEMS is not used to measure GHG emissions, then you must:

(1) Calibrate all oil and gas flow meters (except for gas billing meters), solids weighing equipment, and oil tank drop measurements (if used to determine liquid fuel and feedstock use volume) according to the calibration accuracy requirements in § 98.3(i) of this part.

(2) Determine the carbon content and the molecular weight annually of standard gaseous hydrocarbon fuels and feedstocks having consistent composition (e.g., natural gas). For other gaseous fuels and feedstocks (e.g., biogas, refinery gas, or process gas), weekly sampling and analysis is required to determine the carbon content and molecular weight of the fuel and feedstock.

(3) Determine the carbon content of fuel oil, naphtha, and other liquid fuels and feedstocks at least monthly, except annually for standard liquid hydrocarbon fuels and feedstocks having consistent composition, or upon delivery for liquid fuels delivered by bulk transport (e.g., by truck or rail).

(4) Determine the carbon content of coal, coke, and other solid fuels and feedstocks at least monthly, except annually for standard solid hydrocarbon fuels and feedstocks having consistent composition, or upon delivery for solid fuels delivered by bulk transport (e.g., by truck or rail).

(5) You must use the following applicable methods to determine the carbon content for all fuels and feedstocks, and molecular weight of gaseous fuels and feedstocks.

(i) ASTM D1945–03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, *see* § 98.7).

(ii) ASTM D1946–90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, *see* § 98.7).

(iii) ASTM D2013–07 Standard Practice of Preparing Coal Samples for Analysis (incorporated by reference, *see* § 98.7).

(iv) ASTM D2234/D2234M–07 Standard Practice for Collection of a Gross Sample of Coal (incorporated by reference, *see* § 98.7).

(v) ASTM D2597–94 (Reapproved 2004) Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography (incorporated by reference, *see* § 98.7).

(vi) ASTM D3176–89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, *see* § 98.7).

(vii) ASTM D3238–95 (Reapproved 2005), Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method (incorporated by reference, *see* § 98.7).

(viii) ASTM D4057–06 Standard Practice for Manual Sampling of Petroleum and Petroleum Products (incorporated by reference, *see* § 98.7).

(ix) ASTM D4177–95 (Reapproved 2005) Standard Practice for Automatic Sampling of Petroleum and Petroleum Products (incorporated by reference, *see* § 98.7).

(x) ASTM D5291–02 (Reapproved 2007), Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, *see* § 98.7).

(xi) ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, *see* § 98.7).

(xii) ASTM D6609–08 Standard Guide for Part-Stream Sampling of Coal (incorporated by reference, see § 98.7).

(xiii) ASTM D6883–04 Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles (incorporated by reference, *see* § 98.7).

(xiv) ASTM D7430–08ae1 Standard Practice for Mechanical Sampling of Coal (incorporated by reference, *see* § 98.7).

(xv) ASTM UOP539–97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, *see* § 98.7).

(xvi) GPA 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, *see* § 98.7).

(xvii) ISO 3170: Petroleum Liquids—Manual sampling—Third Edition (incorporated by reference, *see* § 98.7).

(xviii) ISO 3171: Petroleum Liquids—Automatic pipeline sampling—Second Edition (incorporated by reference, *see* § 98.7).

(c) For units using the calculation methodologies described in this section, the records required under § 98.3(g) must include both the company records and a detailed explanation of how company records are used to estimate the following:

(1) Fuel and feedstock consumption, when solid fuel and feedstock is combusted and a CEMS is not used to measure GHG emissions.

(2) Fossil fuel consumption, when, pursuant to § 98.33(e), the owner or operator of a unit that uses CEMS to quantify CO_2 emissions and that combusts both fossil and biogenic fuels separately reports the biogenic portion of the total annual CO_2 emissions.

(3) Sorbent usage, if the methodology in § 98.33(d) is used to calculate CO_2 emissions from sorbent.

(d) The owner or operator must document the procedures used to ensure the accuracy of the estimates of fuel and feedstock usage and sorbent usage (as applicable) in paragraph (b) of this section, including, but not limited to, calibration of weighing equipment, fuel and feedstock flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§ 98.165 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter must be used in the calculations as specified in paragraphs (a), (b), and (c) of this section:

(a) For each missing value of the monthly fuel and feedstock consumption, the substitute data value must be the best available estimate of the fuel and feedstock consumption, based on all available process data (e.g., hydrogen production, electrical load, and operating hours). You must document and keep records of the procedures used for all such estimates.

(b) For each missing value of the carbon content or molecular weight of the fuel and feedstock, the substitute data value must be the arithmetic average of the quality-assured values of carbon contents or molecular weight of the fuel and feedstock immediately preceding and immediately following the missing data incident. If no quality-assured data on carbon contents or molecular weight of the fuel and feedstock are available prior to the missing data incident, the substitute data value must be the first quality-assured value for carbon contents or molecular weight of the fuel and feedstock obtained after the missing data period. You must document and keep records of the procedures used for all such estimates.

(c) For missing CEMS data, you must use the missing data procedures in § 98.35.

§ 98.166 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as appropriate:

(a) If a CEMS is used to measure CO_2 emissions, then you must report the relevant information required under § 98.36 for the Tier 4 Calculation Methodology and the following information in this paragraph (a):

(1) Unit identification number and annual CO_2 process emissions.

(2) Annual quantity of hydrogen produced (metric tons) for each process unit and for all units combined.

(3) Annual quantity of ammonia produced (metric tons), if applicable, for each process unit and for all units combined.

(b) If a CEMS is not used to measure CO_2 emissions, then you must report the following information for each hydrogen production process unit:

(1) Unit identification number and annual CO_2 process emissions.

(2) Monthly consumption of each fuel and feedstock used for hydrogen production and its type (scf of gaseous fuels and feedstocks, gallons of liquid fuels and feedstocks, kg of solid fuels and feedstocks).

(3) Annual quantity of hydrogen produced (metric tons).

(4) Annual quantity of ammonia produced, if applicable (metric tons).

(5) Monthly analyses of carbon content for each fuel and feedstock used in hydrogen production (kg carbon/kg of gaseous and solid fuels and feedstocks, (kg carbon per gallon of liquid fuels and feedstocks).

(6) Monthly analyses of the molecular weight of gaseous fuels and feedstocks (kg/kg-mole) used, if any.

(c) Quarterly quantity of CO_2 collected and transferred off site in either gas, liquid, or solid forms (kg), following the requirements of subpart PP of this part.

(d) Annual quantity of carbon other than CO_2 collected and transferred off site in either gas, liquid, or solid forms (kg carbon).

§ 98.167 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the records specified in paragraphs (a) through (b) of this section for each hydrogen production facility.

(a) If a CEMS is used to measure CO_2 emissions, then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in § 98.37.

(b) If a CEMS is not used to measure CO_2 emissions, then you must retain records of all analyses and calculations conducted as listed in §§ 98.166(b), (c), and (d).

§ 98.168 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart Q—Iron and Steel Production

§ 98.170 Definition of the source category.

The iron and steel production source category includes facilities with any of the following processes: taconite iron ore processing, integrated iron and steel manufacturing, cokemaking not colocated with an integrated iron and steel manufacturing process, and electric arc furnace (EAF) steelmaking not colocated with an integrated iron and steel manufacturing process. Integrated iron and steel manufacturing means the production of steel from iron ore or iron ore pellets. At a minimum, an integrated iron and steel manufacturing process has a basic oxygen furnace for refining molten iron into steel. Each cokemaking process and EAF process located at a facility with an integrated iron and steel manufacturing process is part of the integrated iron and steel manufacturing facility.

§ 98.171 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an iron and steel production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.172 GHGs to report.

(a) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary combustion unit following the requirements of subpart C except for flares. Stationary combustion units include, but are not limited to, by-product recovery coke oven battery combustion stacks, blast furnace stoves, boilers, process heaters, reheat furnaces, annealing furnaces, flame suppression, ladle reheaters, and other miscellaneous combustion sources.

(b) You must report CO_2 emissions from flares according to the procedures in § 98.253(b)(1) of subpart Y (Petroleum Refineries) of this part except you must use the default CO_2 emission factors for coke oven gas and blast furnace gas from Table C–1 of subpart C in Equation Y–1 of subpart Y of this part. You must report CH_4 and N_2O emissions from flares according to the requirements in § 98.33(c)(2) using the emission factors for coke oven gas and blast furnace gas in Table C–2 of subpart C of this part.

(c) You must report process CO_2 emissions from each taconite indurating furnace; basic oxygen furnace; non-recovery coke oven battery combustion stack; coke pushing process; sinter process; EAF; argon-oxygen decarburization vessel; and direct reduction furnace by following the procedures in this subpart.

§ 98.173 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, EAF, argon-oxygen decarburization vessel, and direct reduction furnace using the procedures in either paragraph (a) or (b) of this section. Calculate and report the annual process CO_2 emissions from the coke pushing process according to paragraph (c) of this section.

(a) Calculate and report under this subpart the process CO_2 emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the process CO_2 emissions using the procedure in paragraph (b)(1) or (b)(2) of this section.

(1) *Carbon mass balance method.* Calculate the annual mass emissions of CO_2 for the process as specified in paragraphs (b)(1)(i) through (b)(1)(vii) of this section. The calculations are based on the annual mass of inputs and outputs to the process and an annual analysis of the respective weight fraction of carbon as determined according to the procedures in § 98.174(b). If you have a process input or output other than CO_2 in the exhaust gas that contains carbon that is not included in Equations Q–1 through Q–7 of this section, you must account for the carbon and mass rate of that process input or output in your calculations according to the procedures in § 98.174(b)(5).

(i) For taconite indurating furnaces, estimate CO_2 emissions using Equation Q–1 of this section.

$$CO_2 = \frac{44}{12} * \left[(F_s) * (C_{sf}) + (F_g) * (C_{gf}) * \frac{MW}{MVC} * 0.001 + (F_l) * (C_{lf}) * 0.001 + (O) * (C_o) - (P) * (C_p) - (R) * (C_R) \right] \quad \text{(Eq. Q-1)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the taconite indurating furnace (metric tons).
44/12 = Ratio of molecular weights, CO_2 to carbon.
(F_s) = Annual mass of the solid fuel combusted (metric tons).
(C_{sf}) = Carbon content of the solid fuel, from the fuel analysis (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
(F_g) = Annual volume of the gaseous fuel combusted (scf).
(C_{gf}) = Average carbon content of the gaseous fuel, from the fuel analysis results (kg C per kg of fuel).
MW = Molecular weight of the gaseous fuel (kg/kg-mole).
MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).
0.001 = Conversion factor from kg to metric tons.
(F_l) = Annual volume of the liquid fuel combusted (gallons).
(C_{lf}) = Carbon content of the liquid fuel, from the fuel analysis results (kg C per gallon of fuel).
(O) = Annual mass of greenball (taconite) pellets fed to the furnace (metric tons).
(C_0) = Carbon content of the greenball (taconite) pellets, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(P) = Annual mass of fired pellets produced by the furnace (metric tons).
(C_p) = Carbon content of the fired pellets, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(R) = Annual mass of air pollution control residue collected (metric tons).
(C_R) = Carbon content of the air pollution control residue, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(ii) For basic oxygen process furnaces, estimate CO_2 emissions using Equation Q–2 of this section.

$$CO_2 = \frac{44}{12} * \left[(Iron) * (C_{Iron}) + (Scrap) * (C_{Scrap}) + (Flux) * (C_{Flux}) + (Carbon) * (C_{Carbon}) - (Steel) * (C_{Steel}) - (Slag) * (C_{Slag}) - (R) * (C_R) \right] \quad \text{(Eq. Q-2)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the basic oxygen furnace (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(Iron) = Annual mass of molten iron charged to the furnace (metric tons).

(C_{Iron}) = Carbon content of the molten iron, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(Scrap) = Annual mass of ferrous scrap charged to the furnace (metric tons).

(C_{Scrap}) = Carbon content of the ferrous scrap, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(Flux) = Annual mass of flux materials (e.g., limestone, dolomite) charged to the furnace (metric tons).

(C_{Flux}) = Carbon content of the flux materials, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(Carbon) = Annual mass of carbonaceous materials (e.g., coal, coke) charged to the furnace (metric tons).

(C_{Carbon}) = Carbon content of the carbonaceous materials, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(Steel) = Annual mass of molten raw steel produced by the furnace (metric tons).

(C_{Steel}) = Carbon content of the steel, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(Slag) = Annual mass of slag produced by the furnace (metric tons).

(C_{Slag}) = Carbon content of the slag, from the carbon analysis (percent by weight, expressed as a decimal fraction).

(R) = Annual mass of air pollution control residue collected (metric tons).

(C_R) = Carbon content of the air pollution control residue, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(iii) For non-recovery coke oven batteries, estimate CO_2 emissions using Equation Q–3 of this section.

$$CO_2 = \frac{44}{12} * \left[(Coal) * (C_{Coal}) - (Coke) * (C_{Coke}) - (R) * (C_R) \right] \qquad \text{(Eq. Q-3)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the non-recovery coke oven battery (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(Coal) = Annual mass of coal charged to the battery (metric tons).

(C_{Coal}) = Carbon content of the coal, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(Coke) = Annual mass of coke produced by the battery (metric tons).

(C_{Coke}) = Carbon content of the coke, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(R) = Annual mass of air pollution control residue collected (metric tons).

(C_R) = Carbon content of the air pollution control residue, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(iv) For sinter processes, estimate CO_2 emissions using Equation Q–4 of this section.

$$CO_2 = \frac{44}{12} * \left[(F_g) * (C_{gf}) * \frac{MW}{MVC} * 0.001 + (Feed) * (C_{Feed}) - (\text{Sinter}) * (C_{Sinter}) - (R) * (C_R) \right] \qquad \text{(Eq. Q-4)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the sinter process (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(F_g) = Annual volume of the gaseous fuel combusted (scf).

(C_{gf}) = Carbon content of the gaseous fuel, from the fuel analysis results (kg C per kg of fuel).

MW = Molecular weight of the gaseous fuel (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

0.001 = Conversion factor from kg to metric tons.

(Feed) = Annual mass of sinter feed material (metric tons).

(C_{Feed}) = Carbon content of the mixed sinter feed materials that form the bed entering the sintering machine, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(Sinter) = Annual mass of sinter produced (metric tons).

(C_{Sinter}) = Carbon content of the sinter pellets, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(R) = Annual mass of air pollution control residue collected (metric tons).

(C_R) = Carbon content of the air pollution control residue, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(v) For EAFs, estimate CO_2 emissions using Equation Q–5 of this section.

$$\begin{aligned} CO_2 = \frac{44}{12} * \Big[& (Iron) * (C_{Iron}) + (Scrap) * (C_{Scrap}) + (Flux) \\ & * (C_f) + (Electrode) * (C_{Electrode}) + (Carbon) * (C_c) - (Steel) \\ & * (C_{Steel}) - (Slag) * (C_{Slag}) - (R) * (C_R) \end{aligned} \qquad \text{(Eq. Q-5)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the EAF (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(Iron) = Annual mass of direct reduced iron (if any) charged to the furnace (metric tons).

(C_{Iron}) = Carbon content of the direct reduced iron, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(Scrap) = Annual mass of ferrous scrap charged to the furnace (metric tons).

(C_{Scrap}) = Carbon content of the ferrous scrap, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(Flux) = Annual mass of flux materials (e.g., limestone, dolomite) charged to the furnace (metric tons).

(C_{Flux}) = Carbon content of the flux materials, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(Electrode) = Annual mass of carbon electrode consumed (metric tons).
($C_{Electrode}$) = Carbon content of the carbon electrode, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(Carbon) = Annual mass of carbonaceous materials (e.g., coal, coke) charged to the furnace (metric tons).
(C_{Carbon}) = Carbon content of the carbonaceous materials, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(Steel) = Annual mass of molten raw steel produced by the furnace (metric tons).
(C_{Steel}) = Carbon content of the steel, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(Slag) = Annual mass of slag produced by the furnace (metric tons).
(C_{Slag}) = Carbon content of the slag, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(R) = Annual mass of air pollution control residue collected (metric tons).
(C_R) = Carbon content of the air pollution control residue, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(vi) For argon-oxygen decarburization vessels, estimate CO_2 emissions using Equation Q–6 of this section.

$$CO_2 = \frac{44}{12} * (Steel) * \left[(C_{Steelin}) - (C_{Steelout}) \right] - (R) * (C_R) \qquad \text{(Eq. Q-6)}$$

Where:
CO_2 = Annual CO_2 mass emissions from the argon-oxygen decarburization vessel (metric tons).
44/12 = Ratio of molecular weights, CO_2 to carbon.
(Steel) = Annual mass of molten steel charged to the vessel (metric tons).
($C_{Steelin}$) = Carbon content of the molten steel before decarburization, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
($C_{Steelout}$) = Carbon content of the molten steel after decarburization, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(R) = Annual mass of air pollution control residue collected (metric tons).
(C_R) = Carbon content of the air pollution control residue, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(vii) For direct reduction furnaces, estimate CO_2 emissions using Equation Q–7 of this section.

$$CO_2 = \frac{44}{12} * \left[(F_g) * (C_{gf}) * \frac{MW}{MVC} * 0.001 + (Ore) * (C_{Ore}) \right. \qquad \text{(Eq. Q-7)}$$
$$+ (Carbon) * (C_{Carbon}) + (Other) * (C_{Other})$$
$$\left. - (Iron)\ (C_{Iron}) - (NM) * (C_{NM}) - (R) * (C_R) \right]$$

Where:
CO_2 = Annual CO_2 mass emissions from the direct reduction furnace (metric tons).
44/12 = Ratio of molecular weights, CO_2 to carbon.
(F_g) = Annual volume of the gaseous fuel combusted (scf).
(C_{gf}) = Carbon content of the gaseous fuel, from the fuel analysis results (kg C per kg of fuel).
MW = Molecular weight of the gaseous fuel (kg/kg-mole).
MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).
0.001 = Conversion factor from kg to metric tons.
(Ore) = Annual mass of iron ore or iron ore pellets fed to the furnace (metric tons).
(C_{Ore}) = Carbon content of the iron ore or iron ore pellets, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(Carbon) = Annual mass of carbonaceous materials (e.g., coal, coke) charged to the furnace (metric tons).
(C_{Carbon}) = Carbon content of the carbonaceous materials, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(Other) = Annual mass of other materials charged to the furnace (metric tons).
(C_{Other}) = Average carbon content of the other materials charged to the furnace, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(Iron) = Annual mass of iron produced (metric tons).
(C_{Iron}) = Carbon content of the iron, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(NM) = Annual mass of non-metallic materials produced by the furnace (metric tons).
(C_{NM}) = Carbon content of the non-metallic materials, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(R) = Annual mass of air pollution control residue collected (metric tons).
(C_R) = Carbon content of the air pollution control residue, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(2) *Site-specific emission factor method.* Conduct a performance test and measure CO_2 emissions from all exhaust stacks for the process and measure either the feed rate of materials into the process or the production rate during the test as described in paragraphs (b)(2)(i) through (b)(2)(iv) of this section.

(i) You must measure the process production rate or process feed rate, as applicable, during the performance test according to the procedures in § 98.174(c)(5) and calculate the average rate for the test period in metric tons per hour.

(ii) You must calculate the hourly CO_2 emission rate using Equation Q–8 of this section and determine the average hourly CO_2 emission rate for the test.

$$CO_2 = 5.18 \text{ x } 10^{-7} \star C_{CO2} \star Q \star \left(\frac{100 - \%H_2O}{100} \right) \qquad \text{(Eq. Q-8)}$$

Where:
CO_2 = CO_2 mass emission rate, corrected for moisture (metric tons/hr).
5.18×10^{-7} = Conversion factor (metric tons/scf − % CO_2).

C_{CO2} = Hourly CO_2 concentration, dry basis (% CO_2).
Q = Hourly stack gas volumetric flow rate (scfh).
$\%H_2O$ = Hourly moisture percentage in the stack gas.

(iii) You must calculate a site-specific emission factor for the process in metric tons of CO_2 per metric ton of feed or production, as applicable, by dividing the average hourly CO_2 emission rate during the test by the average hourly feed or production rate during the test.

(iv) You must calculate CO_2 emissions for the process by multiplying the emission factor by the total amount of feed or production, as applicable, for the reporting period.

(c) You must determine emissions of CO_2 from the coke pushing process in $mtCO_2e$ by multiplying the metric tons of coal charged to the coke ovens during the reporting period by 0.008.

(d) If GHG emissions from a taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, EAF, argon-oxygen decarburization vessel, or direct reduction furnace are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

§ 98.174 Monitoring and QA/QC requirements.

(a) If you operate and maintain a CEMS that measures CO_2 emissions consistent with subpart C of this part, you must meet the monitoring and QA/QC requirements of § 98.34(c).

(b) If you determine CO_2 emissions using the carbon mass balance procedure in § 98.173(b)(1), you must:

(1) Except as provided in paragraph (b)(4) of this section, determine the mass of each process input and output other than fuels using the same plant instruments or procedures that are used for accounting purposes (such as weigh hoppers, belt weigh feeders, weighed purchased quantities in shipments or containers, combination of bulk density and volume measurements, etc.), record the totals for each process input and output for each calendar month, and sum the monthly mass to determine the annual mass for each process input and output. Determine the mass rate of fuels using the procedures for combustion units in § 98.34.

(2) Except as provided in paragraph (b)(4) of this section, determine the carbon content of each process input and output annually for use in the applicable equations in § 98.173(b)(1) based on analyses provided by the supplier or by the average carbon content determined by collecting and analyzing at least three samples each year using the standard methods specified in paragraphs (b)(2)(i) through (b)(2)(vi) of this section as applicable.

(i) ASTM C25–06, Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime (incorporated by reference, *see* § 98.7) for limestone, dolomite, and slag.

(ii) ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, *see* § 98.7) for coal, coke, and other carbonaceous materials.

(iii) ASTM E1915–07a, Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry (incorporated by reference, *see* § 98.7) for iron ore, taconite pellets, and other iron-bearing materials.

(iv) ASTM E1019–08, Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel, Iron, Nickel, and Cobalt Alloys by Various Combustion and Fusion Techniques (incorporated by reference, *see* § 98.7) for iron and ferrous scrap.

(v) ASM CS–104 UNS No. G10460—Alloy Digest April 1985 (Carbon Steel of Medium Carbon Content) (incorporated by reference, *see* § 98.7); ISO/TR 15349–1:1998, Unalloyed steel—Determination of low carbon content, Part 1: Infrared absorption method after combustion in an electric resistance furnace (by peak separation) (1998–10–15) First Edition (incorporated by reference, *see* § 98.7); or ISO/TR 15349–3:1998, Unalloyed steel-Determination of low carbon content Part 3: Infrared absorption method after combustion in an electric resistance furnace (with preheating) (1998–10–15) First Edition (incorporated by reference, *see* § 98.7) as applicable for steel.

(vi) For each process input that is a fuel, determine the carbon content and molecular weight (if applicable) using the applicable methods listed in § 98.34.

(3) For solid ferrous materials charged to basic oxygen process furnaces or EAFs that differ in carbon content, you may determine a weighted average carbon content based on the carbon content of each type of ferrous material and the average weight percent of each type that is used. Examples of these different ferrous materials include carbon steel, low carbon steel, stainless steel, high alloy steel, pig iron, iron scrap, and direct reduced iron.

(4) If you document that a specific process input or output contributes less than one percent of the total mass of carbon into or out of the process, you do not have to determine the monthly mass or annual carbon content of that input or output.

(5) Except as provided in paragraph (b)(4) of this section, you must determine the annual carbon content and monthly mass rate of any input or output that contains carbon that is not listed in the equations in § 98.173(b)(1) using the procedures in paragraphs (b)(1) and (b)(2) of this section.

(c) If you determine CO_2 emissions using the site-specific emission factor procedure in § 98.173(b)(2), you must:

(1) Conduct an annual performance test that is based on representative performance (i.e., performance based on normal operating conditions) of the affected process.

(2) For the furnace exhaust from basic oxygen furnaces, EAFs, argon-oxygen decarburization vessels, and direct reduction furnaces, sample the furnace exhaust for at least three complete production cycles that start when the furnace is being charged and end after steel or iron and slag have been tapped. For EAFs that produce both carbon steel and stainless or specialty (low carbon) steel, develop an emission factor for the production of both types of steel.

(3) For taconite indurating furnaces, non-recovery coke batteries, and sinter processes, sample for at least 3 hours.

(4) Conduct the stack test using EPA Method 3A at 40 CFR part 60, appendix A–2 to measure the CO_2 concentration, Method 2, 2A, 2C, 2D, or 2F at 40 CFR part 60, appendix A–1 or Method 26 at 40 CFR part 60, appendix A–2 to determine the stack gas volumetric flow rate, and Method 4 at 40 CFR part 60, at appendix A–3 to determine the moisture content of the stack gas.

(5) Determine the mass rate of process feed or process production (as applicable) during the test using the same plant instruments or procedures that are used for accounting purposes (such as weigh hoppers, belt weigh feeders, combination of bulk density and volume measurements, etc.)

(6) If your process operates under different conditions as part of normal operations in such a manner that CO_2 emissions change by more than 20

percent (e.g., routine changes in the carbon content of the sinter feed or change in grade of product), you must perform emission testing and develop separate emission factors for these different operating conditions and determine emissions based on the number of hours the process operates and the production or feed rate (as applicable) at each specific different condition.

(7) If your EAF and argon-oxygen decarburization vessel exhaust to a common emission control device and stack, you must sample each process in the ducts before the emissions are combined, sample each process when only one process is operating, or sample the combined emissions when both processes are operating and base the site-specific emission factor on the steel production rate of the EAF.

(8) The results of a performance test must include the analysis of samples, determination of emissions, and raw data. The performance test report must contain all information and data used to derive the emission factor.

(d) For a coke pushing process, determine the metric tons of coal charged to the coke ovens and record the totals for each pushing process for each calendar month. Coal charged to coke ovens can be measured using weigh belts or a combination of measuring volume and bulk density.

§ 98.175 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations in § 98.173 is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing data for the carbon content of inputs and outputs for facilities that estimate emissions using the carbon mass balance procedure in § 98.173(b)(1) or for facilities that estimate emissions using the site-specific emission factor procedure in § 98.173(b)(2); 100 percent data availability is required. You must repeat the test for average carbon contents of inputs and outputs according to the procedures in § 98.174(b)(2). Similarly, you must repeat the test to determine the site-specific emission factor if data on the CO_2 emission rate, process production rate or process feed rate are missing.

(b) For missing records of the monthly mass or volume of carbon-containing inputs and outputs using the carbon mass balance procedure in § 98.173(b)(1), the substitute data value must be based on the best available estimate of the mass of the input or output material from all available process data or data used for accounting purposes.

§ 98.176 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information required in paragraphs (a) through (f) of this section for each coke pushing operation; taconite indurating furnace; basic oxygen furnace; non-recovery coke oven battery; sinter process; EAF; argon-oxygen decarburization vessel; and direct reduction furnace:

(a) Unit identification number and annual CO_2 emissions (in metric tons).

(b) Annual production quantity (in metric tons) for taconite pellets, coke, sinter, iron, and raw steel.

(c) If a CEMS is used to measure CO_2 emissions, then you must report the relevant information required under § 98.37 for the Tier 4 Calculation Methodology.

(d) If a CEMS is not used to measure CO_2 emissions, then you must report for each process whether the emissions were determined using the carbon mass balance method in § 98.173(b)(1) or the site-specific emission factor method in § 98.173(b)(2).

(e) If you use the carbon mass balance method in § 98.173(b)(1) to determine CO_2 emissions, you must report the following information for each process:

(1) The carbon content of each process input and output used to determine CO_2 emissions.

(2) Whether the carbon content was determined from information from the supplier or by laboratory analysis, and if by laboratory analysis, the method used.

(3) The annual volume of gaseous fuel (in standard cubic feet), the annual volume of liquid fuel (in gallons), and the annual mass (in metric tons) of all other process inputs and outputs used to determine CO_2 emissions.

(4) The molecular weight of gaseous fuels.

(5) If you used the missing data procedures in § 98.175(b), you must report how the monthly mass for each process input or output with missing data was determined and the number of months the missing data procedures were used.

(f) If you used the site-specific emission factor method in § 98.173(b)(2) to determine CO_2 emissions, you must report the following information for each process:

(1) The measured average hourly CO_2 emission rate during the test (in metric tons per hour).

(2) The average hourly feed or production rate (as applicable) during the test (in metric tons per hour).

(3) The site-specific emission factor (in metric tons of CO_2 per metric ton of feed or production, as applicable).

(4) The annual feed or production rate (as applicable) used to estimate annual CO_2 emissions (in metric tons).

§ 98.177 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) through (e) of this section, as applicable. Facilities that use CEMS to measure emissions must also retain records of the verification data required for the Tier 4 Calculating Methodology in § 98.36(e).

(a) Records of all analyses and calculations conducted, including all information reported as required under § 98.176.

(b) When the carbon mass balance method is used to estimate emissions for a process, the monthly mass of each process input and output that are used to determine the annual mass.

(c) Production capacity (in metric tons per year) for the production of taconite pellets, coke, sinter, iron, and raw steel.

(d) Annual operating hours for taconite furnaces, coke oven batteries, sinter production, blast furnaces, direct reduced iron furnaces, and electric arc furnaces.

(e) Facilities must keep records that include a detailed explanation of how company records or measurements are used to determine all sources of carbon input and output and the metric tons of coal charged to the coke ovens (e.g., weigh belts, a combination of measuring volume and bulk density). You also must document the procedures used to ensure the accuracy of the measurements of fuel usage including, but not limited to, calibration of weighing equipment, fuel flow meters, coal usage including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§ 98.178 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart R—Lead Production

§ 98.180 Definition of the source category.

The lead production source category consists of primary lead smelters and secondary lead smelters. A primary lead smelter is a facility engaged in the production of lead metal from lead sulfide ore concentrates through the use of pyrometallurgical techniques. A secondary lead smelter is a facility at which lead-bearing scrap materials (including but not limited to, lead-acid batteries) are recycled by smelting into elemental lead or lead alloys.

§ 98.181 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a lead production process and the facility meets the requirements of either § 98.2(a)(1) or (a)(2).

§ 98.182 GHGs to report.

You must report:

(a) Process CO_2 emissions from each smelting furnace used for lead production.

(b) CO_2 combustion emissions from each smelting furnace used for lead production.

(c) CH_4 and N_2O combustion emissions from each smelting furnace used for lead production. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) CO_2, CH_4, and N_2O emissions from each stationary combustion unit other than smelting furnaces used for lead production. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§ 98.183 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each smelting furnace using the procedure in paragraphs (a) and (b) of this section.

(a) For each smelting furnace that meets the conditions specified in § 98.33(b)(4)(ii) or (b)(4)(iii), you must calculate and report combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For each smelting furnace that is not subject to the requirements in paragraph (a) of this section, calculate and report the process and combustion CO_2 emissions from the smelting furnace by using the procedure in either paragraph (b)(1) or (b)(2) of this section.

(1) Calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(2) Calculate and report process and combustion CO_2 emissions separately using the procedures specified in paragraphs (b)(2)(i) through (b)(2)(iii) of this section.

(i) For each smelting furnace, determine the annual mass of carbon in each carbon-containing material, other than fuel, that is fed, charged, or otherwise introduced into the smelting furnace and estimate annual process CO_2 emissions using Equation R–1 of this section. Carbon-containing materials include carbonaceous reducing agents. If you document that a specific material contributes less than 1 percent of the total carbon into the process, you do not have to include the material in your calculation using Equation R–1 of this section.

$$E_{CO2} = \frac{44}{12} \times \frac{2000}{2205} \times \left[\left(Ore \times C_{Ore} \right) + \left(Scrap \times C_{Scrap} \right) + \left(Flux \times C_{Flux} \right) + \left(Carbon \times C_{Carbon} \right) + \left(Other \times C_{Other} \right) \right] \quad \text{(Eq. R-1)}$$

Where:

E_{CO2} = Annual process CO_2 emissions from an individual smelting furnace (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

2000/2205 = Conversion factor to convert tons to metric tons.

Ore = Annual mass of lead ore charged to the smelting furnace (tons).

C_{Ore} = Carbon content of the lead ore, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

Scrap = Annual mass of lead scrap charged to the smelting furnace (tons).

C_{Scrap} = Carbon content of the lead scrap, from the carbon analysis (percent by weight, expressed as a decimal fraction).

Flux = Annual mass of flux materials (e.g., limestone, dolomite) charged to the smelting furnace (tons).

C_{Flux} = Carbon content of the flux materials, from the carbon analysis (percent by weight, expressed as a decimal fraction).

Carbon = Annual mass of carbonaceous materials (e.g., coal, coke) charged to the smelting furnace (tons).

C_{Carbon} = Carbon content of the carbonaceous materials, from the carbon analysis (percent by weight, expressed as a decimal fraction).

Other = Annual mass of any other material containing carbon, other than fuel, fed, charged, or otherwise introduced into the smelting furnace (tons).

C_{Other} = Carbon content of the other material from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(ii) Determine the combined annual process CO_2 emissions from the smelting furnaces at your facility using Equation R–2 of this section.

$$CO_2 = \sum_{1}^{k} E_{CO2_k} \quad \text{(Eq. R-2)}$$

Where:

CO_2 = Annual process CO_2 emissions from smelting furnaces at facility used for lead production (metric tons).

E_{CO2_k} = Annual process CO_2 emissions from smelting furnace k calculated using Equation R–1 of this section (metric tons/year).

k = Total number of smelting furnaces at facility used for lead production.

(iii) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion CO_2 emissions from the smelting furnaces according to the applicable requirements in subpart C.

§ 98.184 Monitoring and QA/QC requirements.

If you determine process CO_2 emissions using the carbon mass balance procedure in § 98.183(b)(2)(i) and (b)(2)(ii), you must meet the requirements specified in paragraphs (a) and (b) of this section.

(a) Determine the annual mass for each material used for the calculations of annual process CO_2 emissions using Equation R–1 of this subpart by summing the monthly mass for the material determined for each month of the calendar year. The monthly mass may be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of the material placed in the unit or by calculations using process operating information.

(b) For each material identified in paragraph (a) of this section, you must determine the average carbon content of the material consumed or used in the calendar year using the methods specified in either paragraph (b)(1) or (b)(2) of this section. If you document that a specific process input or output contributes less than one percent of the total mass of carbon into or out of the process, you do not have to determine the monthly mass or annual carbon content of that input or output.

(1) Information provided by your material supplier.

(2) Collecting and analyzing at least three representative samples of the material each year. The carbon content of the material must be analyzed at least annually using the methods (and their QA/QC procedures) specified in paragraphs (b)(2)(i) through (b)(2)(iii) of this section, as applicable.

(i) ASTM E1941–04, Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys (incorporated by reference, see § 98.7) for analysis of metal ore and alloy product.

(ii) ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see § 98.7), for analysis of carbonaceous reducing agents and carbon electrodes.

(iii) ASTM C25–06, Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime (incorporated by reference, see § 98.7) for analysis of flux materials such as limestone or dolomite.

§ 98.185 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations in § 98.183 is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing data for the carbon content for the smelting furnaces at your facility that estimate annual process CO_2 emissions using the carbon mass balance procedure in § 98.183(b)(2)(i) and (ii), 100 percent data availability is required. You must repeat the test for average carbon contents of inputs according to the procedures in § 98.184(b) if data are missing.

(b) For missing records of the monthly mass of carbon-containing materials, the substitute data value must be based the best available estimate of the mass of the material from all available process data or data used for accounting purposes (such as purchase records).

§ 98.186 Data reporting procedures.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable.

(a) If a CEMS is used to measure CO_2 emissions according to the requirements in § 98.183(a) or (b)(1), then you must report under this subpart the relevant information required by § 98.36 and the information specified in paragraphs (a)(1) through (a)(4) of this section.

(1) Identification number of each smelting furnace.

(2) Annual lead product production capacity (tons).

(3) Annual production for each lead product (tons).

(4) Total number of smelting furnaces at facility used for lead production.

(b) If a CEMS is not used to measure CO_2 emissions, and you measure CO_2 emissions according to the requirements in § 98.183(b)(2)(i) and (b)(2)(ii), then you must report the information specified in paragraphs (b)(1) through (b)(9) of this section.

(1) Identification number of each smelting furnace. (2) Annual process CO_2 emissions (in metric tons) from each smelting furnace as determined by Equation R–1 of this subpart.

(3) Annual lead product production capacity for the facility and each smelting furnace(tons).

(4) Annual production for each lead product (tons).

(5) Total number of smelting furnaces at facility used for production of lead products reported in paragraph (b)(4) of this section.

(6) Annual material quantity for each material used for the calculation of annual process CO_2 emissions using Equation R–1 of this subpart for each smelting furnace (tons).

(7) Annual average of the carbon content determinations for each material used for the calculation of annual process CO_2 emissions using Equation R–1 of this subpart for each smelting furnace.

(8) List the method used for the determination of carbon content for each material reported in paragraph (b)(7) of this section (e.g., supplier provided information, analyses of representative samples you collected).

(9) If you use the missing data procedures in § 98.185(b), you must report how the monthly mass of carbon-containing materials with missing data was determined and the number of months the missing data procedures were used.

§ 98.187 Records that must be retained.

In addition to the records required by § 98.3(g), each annual report must contain the information specified in paragraphs (a) through (c) of this section, as applicable to the smelting furnaces at your facility.

(a) If a CEMS is used to measure combined process and combustion CO_2 emissions according to the requirements in § 98.183(a) or (b)(1), then you must retain the records required for the Tier 4 Calculation Methodology in § 98.37 and the information specified in paragraphs (a)(1) through (a)(3) of this section.

(1) Monthly smelting furnace production quantity for each lead product (tons).

(2) Number of smelting furnace operating hours each month.

(3) Number of smelting furnace operating hours in calendar year.

(b) If the carbon mass balance procedure is used to determine process CO_2 emissions according to the requirements in § 98.183(b)(2)(i) and (b)(2)(ii), then you must retain under this subpart the records specified in paragraphs (b)(1) through (b)(5) of this section.

(1) Monthly smelting furnace production quantity for each lead product (tons).

(2) Number of smelting furnace operating hours each month.

(3) Number of smelting furnace operating hours in calendar year.

(4) Monthly material quantity consumed, used, or produced for each material included for the calculations of annual process CO_2 emissions using Equation R–1 of this subpart (tons).

(5) Average carbon content determined and records of the supplier provided information or analyses used for the determination for each material included for the calculations of annual process CO_2 emissions using Equation R–1 of this subpart.

(c) You must keep records that include a detailed explanation of how company records of measurements are used to estimate the carbon input to each smelting furnace, including documentation of any materials excluded from Equation R–1 of this subpart that contribute less than 1 percent of the total carbon into or out of the process. You also must document the procedures used to ensure the accuracy of the measurements of materials fed, charged, or placed in an smelting furnace including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§ 98.188 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart S—Lime Manufacturing

§ 98.190 Definition of the source category.

(a) Lime manufacturing plants (LMPs) engage in the manufacture of a lime product (e.g., calcium oxide, high-calcium quicklime, calcium hydroxide, hydrated lime, dolomitic quicklime, dolomitic hydrate, or other products) by calcination of limestone, dolomite, shells or other cacareous substances as defined in 40 CFR 63.7081(a)(1).

(b) This source category includes all LMPs unless the LMP is located at a kraft pulp mill, soda pulp mill, sulfite pulp mill, or only processes sludge containing calcium carbonate from water softening processes. The lime manufacturing source category consists of marketed and non-marketed lime manufacturing facilities.

(c) Lime kilns at pulp and paper manufacturing facilities must report emissions under subpart AA of this part (Pulp and Paper Manufacturing).

§ 98.191 Reporting threshold.

You must report GHG emissions under this subpart if your facility is a lime manufacturing plant as defined in § 98.190 and the facility meets the requirements of either § 98.2(a)(1) or (a)(2).

§ 98.192 GHGs to report.

You must report:

(a) CO_2 process emissions from lime kilns.

(b) CO_2 emissions from fuel combustion at lime kilns.

(c) N_2O and CH_4 emissions from fuel combustion at each lime kiln. You must report these emissions under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

(d) CO_2, N_2O, and CH_4 emissions from each stationary fuel combustion unit other than lime kilns. You must report these emissions under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

(e) CO_2 collected and transferred off site under 40 CFR part 98, following the requirements of subpart PP of this part (Suppliers of Carbon Dioxide (CO_2)).

§ 98.193 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from all lime kilns combined using the procedure in paragraphs (a) and (b) of this section.

(a) If all lime kilns meet the conditions specified in § 98.33(b)(4)(ii) or (b)(4)(iii), you must calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) If CEMS are not required to be used to determine CO_2 emissions from all lime kilns under paragraph (a) of this section, then you must calculate and report the process and combustion CO_2 emissions from the lime kilns by using the procedures in either paragraph (b)(1) or (b)(2) of this section.

(1) Calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions from all lime kilns according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(2) Calculate and report process and combustion CO_2 emissions separately using the procedures specified in paragraphs (b)(2)(i) through (b)(2)(v) of this section.

(i) You must calculate a monthly emission factor for each type of lime produced using Equation S–1 of this section. Calcium oxide and magnesium oxide content must be analyzed monthly for each lime type:

$$EF_{LIME,i,n} = \left[\left(SR_{CaO} * CaO_{i,n}\right) + \left(SR_{MgO} * MgO_{i,n}\right)\right] * \frac{2000}{2205} \qquad \text{(Eq. S-1)}$$

Where:

$EF_{LIME,i,n}$ = Emission factor for lime type i, for month n (metric tons CO_2/ton lime).

SR_{CaO} = Stoichiometric ratio of CO_2 and CaO for calcium carbonate [see Table S–1 of this subpart] (metric tons CO_2/metric tons CaO).

SR_{MgO} = Stoichiometric ratio of CO_2 and MgO for magnesium carbonate (See Table S–1 of this subpart) (metric tons CO_2/metric tons MgO).

$CaO_{i,n}$ = Calcium oxide content for lime type i, for month n, determined according to § 98.194(c) (metric tons CaO/metric ton lime).

$MgO_{i,n}$ = Magnesium oxide content for lime type i, for month n, determined according to § 98.194(c) (metric tons MgO/metric ton lime).

2000/2205 = Conversion factor for metric tons to tons.

(ii) You must calculate a monthly emission factor for each type of byproduct/waste sold (including lime kiln dust) using Equation S–2 of this section:

$$EF_{LKD,i,n} = \left[\left(SR_{CaO} * CaO_{LKD,i,n}\right) + \left(SR_{MgO} * MgO_{LKD,i,n}\right)\right] * \frac{2000}{2205} \qquad \text{(Eq. S-2)}$$

Where:

$EF_{LKD,i,n}$ = Emission factor for sold lime byproduct/waste type i, for month n (metric tons CO_2/ton lime byproduct).

SR_{CaO} = Stoichiometric ratio of CO_2 and CaO for calcium carbonate (see Table S–1 of this subpart((metric tons CO_2/metric tons CaO).

SR_{MgO} = Stoichiometric ratio of CO_2 and MgO for magnesium carbonate (See Table S–1 of this subpart) (metric tons CO_2/metric tons MgO).

$CaO_{LKD,i,n}$ = Calcium oxide content for sold lime byproduct/waste type i, for month n (metric tons CaO/metric ton lime).

$MgO_{LKD,i,n}$ = Magnesium oxide content for sold lime byproduct/waste type i, for month n (metric tons MgO/metric ton lime).

2000/2205 = Conversion factor for metric tons to tons.

(iii) You must calculate the annual CO_2 emissions from each type of byproduct/waste that is not sold (including lime kiln dust and scrubber sludge) using Equation S–3 of this section:

$$E_{waste,i} = \left[\left(SR_{CaO} * CaO_{waste,i}\right) + \left(SR_{MgO} * MgO_{waste,i}\right)\right] * M_{waste,i} * \frac{2000}{2205} \qquad \text{(Eq. S-3)}$$

Where:

$E_{waste,i}$ = Annual CO_2 emissions for unsold lime byproduct/waste type i (metric tons CO_2).

SR_{CaO} = Stoichiometric ratio of CO_2 and CaO for calcium carbonate (see Table S–1 of this subpart) (metric tons CO_2/metric tons CaO).

SR_{MgO} = Stoichiometric ratio of CO_2 and MgO for magnesium carbonate (See Table S–1 of this subpart) (metric tons CO_2/metric tons MgO).

$CaO_{waste,i}$ = Calcium oxide content for unsold lime byproduct/waste type i (metric tons CaO/metric ton lime).

$MgO_{waste,i}$ = Magnesium oxide content for unsold lime byproduct/waste type i (metric tons MgO/metric ton lime).

$M_{waste,i}$ = Annual weight or mass of unsold byproducts/wastes for lime type i (tons).

2000/2205 = Conversion factor for metric tons to tons.

(iv) You must calculate annual CO_2 process emissions for all kilns using Equation S–4 of this section:

$$E_{CO_2} \sum_{i=1}^{t}\sum_{n=1}^{12}\left(EF_{LIME,i,n} * M_{LIME,i,n}\right) + \sum_{i=1}^{b}\sum_{n=1}^{12} EF_{LKD,i,n} * M_{LKD,i,n}\Big) + \sum_{i=1}^{z} E_{waste,i} \qquad \text{(Eq. S-4)}$$

Where:

E_{CO2} = Annual CO_2 process emissions from lime production from all kilns (metric tons/year).

$EF_{LIME,i,n}$ = Emission factor for lime type i, in calendar month n (metric tons CO_2/ton lime) from Equation S–1 of this section.

$M_{LIME,i,n}$ = Weight or mass of lime type i in calendar month n (tons).

$EF_{LKD,i,n}$ = Emission factor of byproducts/wastes sold for lime type i in calendar month n, (metric tons CO_2/ton byproduct/waste) from Equation S–2 of this section.

$M_{LKD,i,n}$ = Monthly weight or mass of byproducts/waste sold (such as lime kiln dust, LKD) for lime type i in calendar month n (tons).

$E_{waste,i}$ = Annual CO_2 emissions for unsold lime byproduct/waste type i (metric tons CO_2) from Equation S–3 of this section.

t = Number of lime types

b = Number of byproducts/wastes sold

z = Number of byproducts/wastes not sold

(v) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion CO_2 emissions from each lime kiln according to the applicable requirements in subpart C.

§ 98.194 Monitoring and QA/QC requirements.

(a) You must determine the total quantity of each product type of lime and each calcined byproduct/waste (such as lime kiln dust) that is sold. The quantities of each should be directly measured monthly with the same plant instruments used for accounting purposes, including but not limited to, calibrated weigh feeders, rail or truck scales, and barge measurements. The direct measurements of each lime product shall be reconciled annually with the difference in the beginning of and end of year inventories for these products, when measurements represent lime sold.

(b) You must determine the annual quantity of each calcined byproduct/waste generated that is not sold by either direct measurement using the same instruments identified in paragraph (a) of this section or by using a calcined byproduct/waste generation rate.

(c) You must determine the chemical composition (percent total CaO and percent total MgO) of each type of lime and each type of calcined byproduct/waste sold according to paragraph (c)(1) or (c)(2) of this section. You must determine the chemical composition of each type of lime on a monthly basis. You must determine the chemical composition for each type of calcined byproduct/waste that is not sold on an annual basis.

(1) ASTM C25–06 Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime (incorporated by reference—*see* § 98.7).

(2) The National Lime Association's CO_2 Emissions Calculation Protocol for the Lime Industry English Units Version, February 5, 2008 Revision-National Lime Association (incorporated by reference—see § 98.7).

(d) You must use the analysis of calcium oxide and magnesium oxide content of each lime product collected during the same month as the production data in monthly calculations.

(e) You must follow the quality assurance/quality control procedures (including documentation) in National Lime Association's CO_2 Emissions Calculation Protocol for the Lime Industry English Units Version, February 5, 2008 Revision—National Lime Association (incorporated by reference—*see* § 98.7).

§ 98.195 Procedures for estimating missing data.

For the procedure in § 98.193(b)(2), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., oxide content, quantity of lime products, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing value of the quantity of lime produced (by lime type), and quantity of byproduct/waste produced and sold, the substitute data value shall be the best available estimate based on all available process data or data used for accounting purposes.

(b) For missing values related to the CaO and MgO content, you must conduct a new composition test according to the standard methods in § 98.194 (c)(1) or (c)(2).

§ 98.196 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable.

(a) If a CEMS is used to measure CO_2 emissions, then you must report under this subpart the relevant information required by § 98.36 and the information listed in paragraphs (a)(1) through (a)(8) of this section.

(1) Method used to determine the quantity of lime sold.

(2) Method used to determine the quantity of lime byproduct/waste sold.

(3) Beginning and end of year inventories for each lime product.

(4) Beginning and end of year inventories for lime byproducts/wastes.

(5) Annual amount of lime byproduct/waste sold, by type (tons).

(6) Annual amount of lime product sold, by type (tons).

(7) Annual amount of lime byproduct/waste not sold, by type (tons).

(8) Annual amount of lime product not sold, by type (tons).

(b) If a CEMS is not used to measure CO_2 emissions, then you must report the information listed in paragraphs (b)(1) through (b)(17) of this section.

(1) Annual CO_2 process emissions from all kilns combined (metric tons).

(2) Monthly emission factors for each lime type.

(3) Monthly emission factors for each sold byproduct/waste by lime type.

(4) Standard method used (ASTM or NLA testing method) to determine chemical compositions of each lime type and lime byproduct/waste type.

(5) Monthly results of chemical composition analysis of each lime product and byproduct/waste sold.

(6) Annual results of chemical composition analysis of each type of lime byproduct/waste not sold.

(7) Method used to determine the quantity of lime sold.

(8) Monthly amount of lime product sold, by type (tons).

(9) Method used to determine the quantity of lime byproduct/waste sold.

(10) Monthly amount of lime byproduct/waste sold, by type (tons).

(11) Annual amount of lime byproduct/waste not sold (tons).

(12) Monthly mass of each lime type produced (tons).

(13) Beginning and end of year inventories for each lime product.

(14) Beginning and end of year inventories for lime byproducts/wastes.

(15) Annual lime production capacity (tons) per facility.

(16) Number of times in the reporting year that missing data procedures were followed to measure lime production (months) or the chemical composition of lime products sold (months).

(17) Indicate whether CO_2 was used on-site (i.e. for use in a purification process). If CO_2 was used on-site, provide the information in paragraphs (b)(17)(i) and (b)(17)(ii) of this section.

(i) The annual amount of CO_2 captured for use in the on-site process.

(ii) The method used to determine the amount of CO_2 captured.

§ 98.197 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) and (b) of this section.

(a) Annual operating hours in calendar year.

(b) Records of all analyses (e.g. chemical composition of lime products, by type) and calculations conducted.

§ 98.198 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE S–1 TO SUBPART S OF PART 98—BASIC PARAMETERS FOR THE CALCULATION OF EMISSION FACTORS FOR LIME PRODUCTION

Variable	Stoichiometric ratio
SR_{CaO}	0.7848
SR_{MgO}	1.0918

Subpart T—[Reserved]

Subpart U—Miscellaneous Uses of Carbonate

§ 98.210 Definition of the source category.

(a) This source category includes any equipment that uses carbonates listed in Table U–1 in manufacturing processes that emit carbon dioxide. Table U–1 includes the following carbonates: limestone, dolomite, ankerite, magnesite, siderite, rhodochrosite, or sodium carbonate. Facilities are considered to emit CO_2 if they consume at least 2,000 tons per year of carbonates heated to a temperature sufficient to allow the calcination reaction to occur.

(b) This source category does not include equipment that uses carbonates or carbonate containing minerals that are consumed in the production of cement, glass, ferroalloys, iron and steel, lead, lime, phosphoric acid, pulp and paper, soda ash, sodium bicarbonate, sodium hydroxide, or zinc.

(c) This source category does not include carbonates used in sorbent technology used to control emissions from stationary fuel combustion equipment. Emissions from carbonates used in sorbent technology are reported under 40 CFR 98, subpart C (Stationary Fuel Combustion Sources).

§ 98.211 Reporting threshold.

You must report GHG emissions from miscellaneous uses of carbonate if your facility uses carbonates as defined in § 98.210 of this subpart and the facility meets the requirements of either § 98.2(a)(1) or (a)(2).

§ 98.212 GHGs to report.

You must report CO_2 process emissions from all miscellaneous carbonate use at your facility as specified in this subpart.

§ 98.213 Calculating GHG emissions.

You must determine CO_2 process emissions from carbonate use in accordance with the procedures specified in either paragraphs (a) or (b) of this section.

(a) Calculate the process emissions of CO_2 using calcination fractions with Equation U–1 of this section.

$$E_{CO_2} = \sum_{i=1}^{n} M_i * EF_i * F_i * \frac{2000}{2205} \qquad \text{(Eq. U-1)}$$

Where:

E_{CO2} = Annual CO_2 mass emissions from consumption of carbonates (metric tons).

M_i = Annual mass of carbonate type i consumed (tons).

EF_i = Emission factor for the carbonate type i, as specified in Table U–1 to this subpart, metric tons CO_2/metric ton carbonate consumed.

F_i = Fraction calcination achieved for each particular carbonate type i (decimal fraction). As an alternative to measuring the calcination fraction, a value of 1.0 can be used.

n = Number of carbonate types.

2000/2205 = Conversion factor to convert tons to metric tons.

(b) Calculate the process emissions of CO_2 using actual mass of output carbonates with Equation U–2 of this section.

$$E_{CO_2} = \left[\sum_{k=1}^{m} \left(M_k * EF_k\right) - \sum_{j=1}^{n} \left(M_j * EF_j\right) \right] * \frac{2000}{2205} \qquad \text{(Eq. U-2)}$$

Where:

E_{CO2} = Annual CO_2 mass emissions from consumption of carbonates (metric tons).

M_k = Annual mass of input carbonate type k (tons).

EF_k = Emission factor for the carbonate type k, as specified in Table U–1 of this subpart (metric tons CO_2/metric ton carbonate input).

M_j = Annual mass of output carbonate type j (tons).

EF_j = Emission factor for the output carbonate type j, as specified in Table U–1 of this subpart (metric tons CO_2/metric ton carbonate input).

m = Number of input carbonate types.

n = Number of output carbonate types.

§ 98.214 Monitoring and QA/QC requirements.

(a) The annual mass of carbonate consumed (for Equation U–1 of this subpart) or carbonate inputs (for Equation U–2 of this subpart) must be determined annually from monthly measurements using the same plant instruments used for accounting purposes including purchase records or direct measurement, such as weigh hoppers or weigh belt feeders.

(b) The annual mass of carbonate outputs (for Equation U–2 of this subpart) must be determined annually from monthly measurements using the same plant instruments used for accounting purposes including purchase records or direct measurement, such as weigh hoppers or belt weigh feeders.

(c) If you follow the procedures of § 98.213(a), as an alternative to assuming a calcination fraction of 1.0, you can determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis using a suitable method such as using an x-ray fluorescence standard method or other enhanced industry consensus standard method published by an industry consensus standard organization (e.g., ASTM, ASME, etc.).

§ 98.215 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraph (b) of this section. You must document and keep records of the procedures used for all such estimates.

(b) For each missing value of monthly carbonate consumed, monthly carbonate output, or monthly carbonate input, the substitute data value must be the best available estimate based on the all available process data or data used for accounting purposes.

§ 98.216 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) through (g) of this section at the facility level, as applicable.

(a) Annual CO_2 emissions from miscellaneous carbonate use (metric tons).

(b) Annual mass of each carbonate type consumed (tons).

(c) Measurement method used to determine the mass of carbonate.

(d) Method used to calculate emissions.

(e) If you followed the calculation method of § 98.213(b)(1)(i), you must report the information in paragraphs (e)(1) through (e)(3) of this section.

(1) Annual carbonate consumption by carbonate type (tons).

(2) Annual calcination fractions used in calculations.

(3) If you determined the calcination fraction, indicate which standard method was used.

(f) If you followed the calculation method of § 98.213(b)(1)(ii), you must report the information in paragraphs (f)(1) and (f)(2) of this section.

(1) Annual carbonate input by carbonate type (tons).

(2) Annual carbonate output by carbonate type (tons).

(g) Number of times in the reporting year that missing data procedures were followed to measure carbonate consumption, carbonate input or carbonate output (months).

§ 98.217 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) through (d) of this section:

(a) Monthly carbonate consumption (by carbonate type in tons).

(b) You must document the procedures used to ensure the accuracy of the monthly measurements of carbonate consumption, carbonate input or carbonate output including, but not limited to, calibration of weighing equipment and other measurement devices.

(c) Records of all analyses conducted to meet the requirements of this rule.

(d) Records of all calculations conducted.

§ 98.218 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE U–1 TO SUBPART U OF PART 98—CO_2 EMISSION FACTORS FOR COMMON CARBONATES

Mineral name—carbonate	CO_2 emission factor (tons CO_2/ton carbonate)
Limestone—$CaCO_3$	0.43971
Magnesite—$MgCO_3$	0.52197
Dolomite—$CaMg(CO_3)_2$	0.47732
Siderite—$FeCO_3$	0.37987
Ankerite—Ca(Fe, Mg, Mn)$(CO_3)_2$	0.47572
Rhodochrosite—$MnCO_3$	0.38286
Sodium Carbonate/Soda Ash—Na_2CO_3	0.41492

Subpart V—Nitric Acid Production

§ 98.220 Definition of source category.

A nitric acid production facility uses one or more trains to produce weak nitric acid (30 to 70 percent in strength). A nitric acid train produces weak nitric acid through the catalytic oxidation of ammonia.

§ 98.221 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a nitric acid train and the facility meets the requirements of either § 98.2(a)(1) or (a)(2).

§ 98.222 GHGs to report.

(a) You must report N_2O process emissions from each nitric acid production train as required by this subpart.

(b) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary combustion unit by following the requirements of subpart C.

§ 98.223 Calculating GHG emissions.

(a) You must determine annual N_2O process emissions from each nitric acid train according to paragraphs (a)(1) or (a)(2) of this section.

(1) Use a site-specific emission factor and production data according to paragraphs (b) through (h) of this section.

(2) Request Administrator approval for an alternative method of determining N_2O emissions according to paragraphs (a)(2)(i) and (a)(2)(ii) of this section.

(i) You must submit the request within 45 days following promulgation of this subpart or within the first 30 days of each subsequent reporting year.

(ii) If the Administrator does not approve your requested alternative method within 150 days of the end of the reporting year, you must determine the N_2O emissions factor for the current reporting period using the procedures specified in paragraph (a)(1) of this section.

(b) You must conduct an annual performance test according to paragraphs (b)(1) through (b)(3) of this section.

(1) You must measure N_2O emissions from the absorber tail gas vent for each nitric acid train using the methods specified in § 98.224(b) through (d).

(2) You must conduct the performance test under normal process operating conditions and without using N_2O abatement technology (if applicable).

(3) You must measure the production rate during the performance test and calculate the production rate for the test period in metric tons (100 percent acid basis) per hour.

(c) You must determine an N_2O emissions factor to use in Equation V–3 of this section according to paragraphs (c)(1) or (c)(2) of this section.

(1) You may request Administrator approval for an alternative method of determining N_2O concentration according to the procedures in paragraphs (a)(2)(i) and (a)(2)(ii) of this section. Alternative methods include the use of N_2O CEMs.

(2) Using the results of the performance test in paragraph (b) of this section, you must calculate an average site-specific emission factor for each nitric acid train "t" according to Equation V–1 of this section:

$$EF_{N2Ot} = \frac{\sum_{1}^{n} \frac{C_{N2O} * 1.14 \times 10^{-7} * Q}{P}}{n} \qquad \text{(Eq. V-1)}$$

Where:

EF_{N2Ot} = Average site-specific N_2O emissions factor for nitric acid train "t" (lb N_2O generated/ton nitric acid produced, 100 percent acid basis).

C_{N2O} = N_2O concentration for each test run during the performance test (ppm N_2O).

1.14×10^{-7} = Conversion factor (lb/dscf-ppm N_2O).

Q = Volumetric flow rate of effluent gas for each test run during the performance test (dscf/hr).

P = Production rate for each test run during the performance test (tons nitric acid produced per hour, 100 percent acid basis).

n = Number of test runs.

(d) If applicable, you must determine the destruction efficiency for each N_2O abatement technology according to paragraphs (d)(1), (d)(2), or (d)(3) of this section.

(1) Use the manufacturer's specified destruction efficiency.

(2) Estimate the destruction efficiency through process knowledge. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current vent stream conditions. You must document how process knowledge (if applicable) was used to determine the destruction efficiency.

(3) Calculate the destruction efficiency by conducting an additional performance test on the emissions stream following the N_2O abatement technology.

(e) If applicable, you must determine the abatement factor for each N_2O abatement technology. The abatement factor is calculated for each nitric acid train according to Equation V–2 of this section.

$$AF_{N\,t} = \frac{P_{a\,t\,Abate}}{P_{a\,t}} \qquad \text{(Eq. V-2)}$$

Where:

$AF_{N\,t}$ = Abatement factor of N_2O abatement technology at nitric acid train "t" (fraction of annual production that abatement technology is operating).

$P_{a\,t}$ = Total annual nitric acid production from nitric acid train "t" (ton acid produced, 100 percent acid basis).

$P_{a\,t\,Abate}$ = Annual nitric acid production from nitric acid train "t" during which N_2O abatement was used (ton acid produced, 100 percent acid basis).

(f) You must determine the annual amount of nitric acid produced and the annual amount of nitric acid produced while each N_2O abatement technology is operating from each nitric acid train (100 percent basis).

(g) You must calculate N_2O emissions for each nitric acid train by multiplying the emissions factor (determined in Equation V–1 of this section) by the annual nitric acid production and accounting for N_2O abatement, according to Equation V–3 of this section:

$$EF_{N_2Ot} = \sum_{N=1}^{z} \frac{EF_{N2Ot} * P_{a\,t} * \left(1 - \left(DF_{N\,t} * AF_{N\,t}\right)\right)}{2204.63} \qquad \text{(Eq. V-3)}$$

Where:

E_{N2Ot} = N_2O mass emissions per year for nitric acid train "t" (metric tons).

EF_{N2Ot} = Average site-specific N_2O emissions factor for nitric acid train "t" (lb N_2O generated/ton acid produced, 100 percent acid basis).

$P_{a\,t}$ = Annual nitric acid production from the train "t" (ton acid produced, 100 percent acid basis).

$DF_{N\,t}$ = Destruction efficiency of N_2O abatement technology N that is used on nitric acid train "t" (percent of N_2O removed from air stream).

$AF_{N\,t}$ = Abatement factor of N_2O abatement technology for nitric acid train "t" (fraction of annual production that abatement technology is operating).

2204.63 = Conversion factor (lb/metric ton).

z = Number of different N_2O abatement technologies.

(h) You must determine the annual nitric acid production emissions combined from all nitric acid trains at your facility using Equation V–4 of this section:

$$N_2O = \sum_{t=1}^{m} E_{N2Ot} \qquad \text{(Eq. V-4)}$$

Where:

N_2O = Annual process N_2O emissions from nitric acid production facility (metric tons).

E_{N2Ot} = N_2O mass emissions per year for nitric acid train ''t'' (metric tons).

m = Number of nitric acid trains.

§ 98.224 Monitoring and QA/QC requirements.

(a) You must conduct a new performance test and calculate a new site-specific emissions factor according to a test plan as specified in paragraphs (a)(1) through (a)(3) of this section.

(1) Conduct the performance test annually.

(2) Conduct the performance test when your nitric acid production process is changed, specifically when abatement equipment is installed.

(3) If you requested Administrator approval for an alternative method of determining N_2O concentration under § 98.223(a)(2), you must conduct the performance test if your request has not been approved by the Administrator within 150 days of the end of the reporting year in which it was submitted.

(b) You must measure the N_2O concentration during the performance test using one of the methods in paragraphs (b)(1) through (b)(3) of this section.

(1) EPA Method 320 at 40 CFR part 63, appendix A, Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy.

(2) ASTM D6348–03 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy (incorporated by reference in § 98.7).

(3) An equivalent method, with Administrator approval.

(c) You must determine the production rate(s) (100 percent basis) from each nitric acid train during the performance test according to paragraphs (c)(1) or (c)(2) of this section.

(1) Direct measurement of production and concentration (such as using flow meters, weigh scales, for production and concentration measurements).

(2) Existing plant procedures used for accounting purposes (i.e. dedicated tank-level and acid concentration measurements).

(d) You must conduct all performance tests in conjunction with the applicable EPA methods in 40 CFR part 60, appendices A–1 through A–4. Conduct three emissions test runs of 1 hour each. All QA/QC procedures specified in the reference test methods and any associated performance specifications apply. For each test, the facility must prepare an emission factor determination report that must include the items in paragraphs (d)(1) through (d)(3) of this section.

(1) Analysis of samples, determination of emissions, and raw data.

(2) All information and data used to derive the emissions factor(s).

(3) The production rate during each test and how it was determined.

(e) You must determine the monthly nitric acid production and the monthly nitric acid production during which N_2O abatement technology is operating from each nitric acid train according to the methods in paragraphs (c)(1) or (c)(2) of this section.

(f) You must determine the annual nitric acid production and the annual nitric acid production during which N_2O abatement technology is operating for each train by summing the respective monthly nitric acid production quantities.

§ 98.225 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section.

(a) For each missing value of nitric acid production, the substitute data shall be the best available estimate based on all available process data or data used for accounting purposes (such as sales records).

(b) For missing values related to the performance test, including emission factors, production rate, and N_2O concentration, you must conduct a new performance test according to the procedures in § 98.224 (a) through (d).

§ 98.226 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) through (o) of this section for each nitric acid production train.

(a) Train identification number.

(b) Annual process N_2O emissions from each nitric acid train (metric tons).

(c) Annual nitric acid production from each nitric acid train (tons, 100 percent acid basis).

(d) Annual nitric acid production from each nitric acid train during which N_2O abatement technology is operating (ton acid produced, 100 percent acid basis).

(e) Annual nitric acid production from the nitric acid facility (tons, 100 percent acid basis).

(f) Number of nitric acid trains.

(g) Number of abatement technologies (if applicable).

(h) Abatement technologies used (if applicable).

(i) Abatement technology destruction efficiency for each abatement technology (percent destruction).

(j) Abatement utilization factor for each abatement technology (fraction of annual production that abatement technology is operating).

(k) Type of nitric acid process used for each nitric acid train (low, medium, high, or dual pressure).

(l) Number of times in the reporting year that missing data procedures were followed to measure nitric acid production (months).

(m) If you conducted a performance test and calculated a site-specific emissions factor according to § 98.223(a)(1), each annual report must also contain the information specified in paragraphs (m)(1) through (m)(7) of this section for each nitric acid production facility.

(1) Emission factor calculated for each nitric acid train (lb N_2O/ton nitric acid, 100 percent acid basis).

(2) Test method used for performance test.

(3) Production rate per test run during performance test (tons nitric acid produced/hr, 100 percent acid basis).

(4) N_2O concentration per test run during performance test (ppm N_2O).

(5) Volumetric flow rate per test run during performance test (dscf/hr).

(6) Number of test runs during performance test.

(7) Number of times in the reporting year that a performance test had to be repeated (number).

(n) If you requested Administrator approval for an alternative method of determining N_2O concentration under § 98.223(a)(2), each annual report must also contain the information specified in paragraphs (n)(1) through (n)(4) of this section for each nitric acid production facility.

(1) Name of alternative method.

(2) Description of alternative method.

(3) Request date.

(4) Approval date.

(o) Total pounds of synthetic fertilizer produced through and total nitrogen contained in that fertilizer.

§ 98.227 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the records specified in paragraphs (a) through (g) of this section for each nitric acid production facility:

(a) Records of significant changes to process.

(b) Documentation of how process knowledge was used to estimate abatement technology destruction efficiency (if applicable).

(c) Performance test reports.

(d) Number of operating hours in the calendar year for each nitric acid train (hours).

(e) Annual nitric acid permitted production capacity (tons).

(f) Measurements, records, and calculations used to determine reported parameters.

(g) Documentation of the procedures used to ensure the accuracy of the measurements of all reported parameters, including but not limited to, calibration of weighing equipment, flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§ 98.228 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart W—[Reserved]

Subpart X—Petrochemical Production

§ 98.240 Definition of the source category.

(a) The petrochemical production source category consists of all processes that produce acrylonitrile, carbon black, ethylene, ethylene dichloride, ethylene oxide, or methanol, except as specified in paragraphs (b) through (f) of this section. The source category includes processes that produce the petrochemical as an intermediate in the onsite production of other chemicals as well as processes that produce the petrochemical as an end product for sale or shipment offsite.

(b) A process that produces a petrochemical as a byproduct is not part of the petrochemical production source category.

(c) A facility that makes methanol, hydrogen, and/or ammonia from synthesis gas is part of the petrochemical source category if the annual mass of methanol produced exceeds the individual annual mass production levels of both hydrogen recovered as product and ammonia. The facility is part of subpart P of this part (Hydrogen Production) if the annual mass of hydrogen recovered as product exceeds the individual annual mass production levels of both methanol and ammonia. The facility is part of subpart G of this part (Ammonia Manufacturing) if the annual mass of ammonia produced exceeds the individual annual mass production levels of both hydrogen recovered as product and methanol.

(d) A direct chlorination process that is operated independently of an oxychlorination process to produce ethylene dichloride is not part of the petrochemical production source category.

(e) A process that produces bone black is not part of the petrochemical source category.

(f) A process that produces a petrochemical from bio-based feedstock is not part of the petrochemical production source category.

§ 98.241 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a petrochemical process as specified in § 98.240, and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.242 GHGs to report.

You must report the information in paragraphs (a) through (c) of this section:

(a) CO_2 CH_4, and N_2O process emissions from each petrochemical process unit. Process emissions include CO_2 generated by reaction in the process and by combustion of process off-gas in stationary combustion units and flares.

(1) If you comply with § 98.243(b) or (d), report under this subpart the calculated CO_2, CH_4, and N_2O emissions for each stationary combustion source and flare that burns any amount of petrochemical process off-gas.

(2) If you comply with § 98.243(c), report under this subpart the calculated CO_2 emissions for each petrochemical process unit.

(b) CO_2, CH_4, and N_2O combustion emissions from stationary combustion units and flares.

(1) If you comply with § 98.243(b) or (d), report these emissions from stationary combustion units that are associated with petrochemical process units and burn only supplemental fuel under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(2) If you comply with § 98.243(c), report CO_2, CH_4, and N_2O combustion emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C only for the combustion of supplemental fuel. Determine the applicable Tier in subpart C of this part (General Stationary Fuel Combustion Sources) based on the maximum rated heat input capacity of the stationary combustion source.

(c) CO_2 captured. You must report the mass of CO_2 captured under, subpart PP of this part (Suppliers of Carbon Dioxide (CO_2) by following the requirements of subpart PP.

§ 98.243 Calculating GHG emissions.

(a) If you route all process vent emissions and emissions from combustion of process off-gas to one or more stacks and use CEMS on each stack to measure CO_2 emissions (except flare stacks), then you must determine process-based GHG emissions in accordance with paragraph (b) of this section. Otherwise, determine process-based GHG emissions in accordance with the procedures specified in paragraph (c) or (d) of this section.

(b) *Continuous emission monitoring system (CEMS).* Route all process vent emissions and emissions from combustion of process off-gas to one or more stacks and determine CO_2 emissions from each stack (except flare stacks) according to the Tier 4 Calculation Methodology requirements in subpart C of this part. For each stack (except flare stacks) that includes emissions from combustion of petrochemical process off-gas, calculate CH_4 and N_2O emissions in accordance with subpart C of this part (use the Tier 3 methodology and emission factors for ''Petroleum'' in Table C–2 of subpart C of this part). For each flare, calculate CO_2, CH_4, and N_2O emissions using the methodology specified in § 98.253(b)(1) through (b)(3).

(c) *Mass balance for each petrochemical process unit.* Calculate the emissions of CO_2 from each process unit, for each calendar month as described in paragraphs (c)(1) through (c)(5) of this section.

(1) For each gaseous and liquid feedstock and product, measure the volume or mass used or produced each calendar month with a flow meter by following the procedures specified in § 98.244(b)(2). Alternatively, for liquids, you may calculate the volume used or collected in each month based on measurements of the liquid level in a storage tank at least once per month (and just prior to each change in direction of the level of the liquid) following the procedures specified in § 98.244(b)(3). Fuels used for combustion purposes are not considered to be feedstocks.

(2) For each solid feedstock and product, measure the mass used or produced each calendar month by following the procedures specified in § 98.244(b)(1).

(3) Collect a sample of each feedstock and product at least once per month and determine the carbon content of each

sample according to the procedures in § 98.244(b)(4). Alternatively, you may use the results of analyses conducted by a fuel or feedstock supplier, provided the sampling and analysis are conducted at least once per month using any of the procedures specified in § 98.244(b)(4). If multiple valid carbon content measurements are made during the monthly measurement period, average them arithmetically.

(4) If you determine that the monthly average concentration of a specific compound in a feedstock or product is greater than 99.5 percent by volume (or mass for liquids and solids), then as an alternative to the sampling and analysis specified in paragraph (c)(3) of this section, you may calculate the carbon content assuming 100 percent of that feedstock or product is the specific compound during periods of normal operation. You must maintain records of any determination made in accordance with this paragraph (c)(4) along with all supporting data, calculations, and other information. This alternative may not be used for products during periods of operation when off-specification product is produced. You must reevaluate determinations made under this paragraph (c)(4) after any process change that affects the feedstock or product composition. You must keep records of the process change and the corresponding composition determinations. If the feedstock or product composition changes so that the average monthly concentration falls below 99.5 percent, you are no longer permitted to use this alternative method.

(5) Calculate the CO_2 mass emissions for each petrochemical process unit using Equations X–1 through X–4 of this section.

(i) *Gaseous feedstocks and products.* Use Equation X–1 of this section to calculate the net annual carbon input or output from gaseous feedstocks and products. Note that the result will be a negative value if there are no gaseous feedstocks in the process but there are gaseous products.

$$C_g = \sum_{n=1}^{12}\left[\sum_{i=1}^{j\ or\ k}\left[\left(F_{gf}\right)_{i,n} * \left(CC_{gf}\right)_{i,n} * \frac{\left(MW_f\right)_i}{MVC} - \left(P_{gp}\right)_{i,n} * \left(CC_{gp}\right)_{i,n} * \frac{\left(MW_p\right)_i}{MVC}\right]\right] \qquad \text{(Eq. X-1)}$$

Where:

C_g = Annual net contribution to calculated emissions from carbon (C) in gaseous materials (kilograms/year, kg/yr).

$(F_{gf})_{i,n}$ = Volume of gaseous feedstock i introduced in month ''n'' (standard cubic feet, scf).

$(CC_{gf})_{i,n}$ = Average carbon content of the gaseous feedstock i for month ''n'' (kg C per kg of feedstock).

$(MW_f)_i$ = Molecular weight of gaseous feedstock i (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

$(P_{gp})_{i,n}$ = Volume of gaseous product i produced in month ''n'' (scf).

$(CC_{gp})_{i,n}$ = Average carbon content of gaseous product i, including streams containing CO_2 recovered for sale or use in another process, for month ''n'' (kg C per kg of product).

$(MW_p)_i$ = Molecular weight of gaseous product i (kg/kg-mole).

j = Number of feedstocks.

k = Number of products.

(ii) *Liquid feedstocks and products.* Use Equation X–2 of this section to calculate the net carbon input or output from liquid feedstocks and products. Note that the result will be a negative value if there are no liquid feedstocks in the process but there are liquid products.

$$C_l = \sum_{n=1}^{12}\left[\sum_{i=1}^{j\ or\ k}\left[\left(F_{lf}\right)_{i,n} * \left(CC_{lf}\right)_{i,n} - \left(P_{lp}\right)_{i,n} * \left(CC_{lp}\right)_{i,n}\right]\right] \qquad \text{(Eq. X-2)}$$

Where:

C_l = Annual net contribution to calculated emissions from carbon in liquid materials, including liquid organic wastes (kg/yr).

$(F_{lf})_{i,n}$ = Volume or mass of liquid feedstock i introduced in month ''n'' (gallons or kg).

$(CC_{lf})_{i,n}$ = Average carbon content of liquid feedstock i for month ''n'' (kg C per gallon or kg of feedstock).

$(P_{lp})_{i,n}$ = Volume or mass of liquid product i produced in month ''n'' (gallons or kg).

$(CC_{lp})_{i,n}$ = Average carbon content of liquid product i, including organic liquid wastes, for month ''n'' (kg C per gallon or kg of product).

j = Number of feedstocks.

k = Number of products.

(iii) *Solid feedstocks and products.* Use Equation X–3 of this section to calculate the net annual carbon input or output from solid feedstocks and products. Note that the result will be a negative value if there are no solid feedstocks in the process but there are solid products.

$$C_s = \sum_{n=1}^{12}\left\{\sum_{i=1}^{j\ or\ k}\left[\left(F_{sf}\right)_{i,n} * \left(CC_{sf}\right)_{i,n} - \left(P_{sp}\right)_{i,n} * \left(CC_{sp}\right)_{i,n}\right]\right\} \qquad \text{(Eq. X-3)}$$

Where:

C_s = Annual net contribution to calculated emissions from carbon in solid materials (kg/yr).

$(F_{sf})_{i,n}$ = Mass of solid feedstock i introduced in month ''n'' (kg).

$(CC_{sf})_{i,n}$ = Average carbon content of solid feedstock i for month ''n'' (kg C per kg of feedstock).

$(P_{sp})_{i,n}$ = Mass of solid product i produced in month ''n'' (kg).

$(CC_{sp})_{i,n}$ = Average carbon content of solid product i in month ''n'' (kg C per kg of product).

j = Number of feedstocks.

k = Number of products.

(iv) *Annual emissions.* Use the results from Equations X–1 through X–3 of this section, as applicable, in Equation X–4 of this section to calculate annual CO_2 emissions.

$$CO_2 = 0.001 * \frac{44}{12} * \left(C_g + C_l + C_s\right) \qquad \text{(Eq. X-4)}$$

Where:

CO_2 = Annual CO_2 mass emissions from process operations and process off-gas combustion (metric tons/year).

0.001 = Conversion factor from kg to metric tons.

44 = Molecular weight of CO_2 (kg/kg-mole).

12 = Atomic weight of carbon (C) (kg/kg-mole).

(d) *Optional combustion methodology for ethylene production processes.* For any ethylene production process, calculate CO_2 emissions from combustion of fuel that contains ethylene process off-gas using the Tier 3 or Tier 4 methodology in subpart C of this part, and calculate CH_4 and N_2O emissions using the applicable procedures in § 98.33(c) (use the emission factors for ''Petroleum'' in Table C–2 of subpart C of this part (General Stationary Fuel Combustion Sources)). You are not required to use the same Tier for each stationary combustion unit that burns ethylene process off-gas. For each flare, calculate CO_2, CH_4, and N_2O emissions using the methodology specified in § 98.253(b)(1) through (b)(3).

§ 98.244 Monitoring and QA/QC requirements.

(a) If you use CEMS to determine emissions from process vents, you must comply with the procedures specified in § 98.34(c).

(b) If you use the mass balance methodology in § 98.243(c), use the procedures specified in paragraphs (b)(1) through (b)(4) of this section to determine feedstock and product flows and carbon contents.

(1) Operate and maintain belt scales or other weighing devices as described in Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices NIST Handbook 44 (2009) (incorporated by reference, *see* § 98.7) or follow procedures specified by the measurement device manufacturer. Calibrate the measurement device according to the procedures specified by the method, the procedures specified by the manufacturer, or § 98.3(i). Recalibrate either biennially or at the minimum frequency specified by the manufacturer.

(2) Operate and maintain all flow meters for gas and liquid feedstocks and products by following the procedures in § 98.3(i) and using any of the flow meter methods specified in paragraphs (b)(2)(i) through (b)(2)(xv) of this section, as applicable, use a standard method published by a consensus-based standards organization (e.g., ASTM, API, etc.), or follow procedures specified by the flow meter manufacturer or § 98.3(i). Recalibrate each flow meter either biennially or at the minimum frequency specified by the manufacturer.

(i) ASME MFC–3M–2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, *see* § 98.7).

(ii) ASME MFC–4M–1986 (Reaffirmed 1997) Measurement of Gas Flow by Turbine Meters (incorporated by reference, *see* § 98.7).

(iii) ASME MFC–5M–1985 (Reaffirmed 1994) Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters (incorporated by reference, *see* § 98.7).

(iv) ASME MFC–6M–1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, *see* § 98.7).

(v) ASME MFC–7M–1987 (Reaffirmed 1992) Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, *see* § 98.7).

(vi) ASME MFC–9M–1988 (Reaffirmed 2001) Measurement of Liquid Flow in Closed Conduits by Weighing Method (incorporated by reference, *see* § 98.7).

(vii) ASME MFC–11M–2006 Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters (incorporated by reference, *see* § 98.7).

(viii) ASME MFC–14M–2003 (Reaffirmed 2008), Measurement of Fluid Flow Using Small Bore Precision Orifice Meters (incorporated by reference, *see* § 98.7).

(ix) ASME MFC–16–2007 Measurement of Liquid Flow in Closed Conduits with Electromagnetic Flowmeters (incorporated by reference, *see* § 98.7).

(x) ASME MFC–18M–2001 (Reaffirmed 2006), Measurement of Fluid Flow Using Variable Area Meters (incorporated by reference, *see* § 98.7).

(xi) ASME MFC–22–2007 Measurement of Liquid by Turbine Flowmeters (incorporated by reference, *see* § 98.7).

(xii) AGA Report No. 3: Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines (1990), Part 2: Specification and Installation Requirements (2000) (incorporated by reference, *see* § 98.7).

(xiii) AGA Transmission Measurement Committee Report No. 7: Measurement of Natural Gas by Turbine Meter (2006)/February (incorporated by reference, *see* § 98.7).

(xiv) AGA Report No. 11: Measurement of Natural Gas by Coriolis Meter (2003) (incorporated by reference, *see* § 98.7).

(xv) ISO 8316: Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank (1987–10–01) First Edition (incorporated by reference, *see* § 98.7).

(3) Perform tank level measurements (if used to determine feedstock or product flows) according to any standard method published by a consensus-based standards organization (e.g., ASTM, API, etc.) or follow procedures specified by the measurement device manufacturer or § 98.3(i). Calibrate the measurement devices prior to the effective date of the rule, and recalibrate either biennially or at the minimum frequency specified by the manufacturer or § 98.3(i).

(4) Use any of the standard methods specified in paragraphs (b)(4)(i) through (b)(4)(x) of this section, as applicable, to determine the carbon content or composition of feedstocks and products and the average molecular weight of gaseous feedstocks and products. Calibrate instruments in accordance with the method and as specified in paragraphs (b)(4)(i) through (b)(4)(x), as applicable. For coal used as a feedstock, the samples for carbon content determinations shall be taken at a location that is representative of the coal feedstock used during the corresponding monthly period. For carbon black products, samples shall be taken of each grade or type of product produced during the monthly period. Samples of coal feedstock or carbon black product for carbon content determinations may be either grab samples collected and analyzed monthly or a composite of samples collected more frequently and analyzed monthly. Analyses conducted in accordance with methods specified in paragraphs (b)(4)(i) through (b)(4)(x) of this section may be performed by the owner or operator, by an indpendent laboratory, or by the supplier of a feedstock.

(i) ASTM D1945–03, Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, *see* § 98.7).

(ii) ASTM D6060–96 (Reapproved 2001) Standard Practice for Sampling of Process Vents With a Portable Gas

Chromatograph (incorporated by reference, *see* § 98.7).

(iii) ASTM D2505–88(Reapproved 2004)e1 Standard Test Method for Ethylene, Other Hydrocarbons, and Carbon Dioxide in High-Purity Ethylene by Gas Chromatography (incorporated by reference, *see* § 98.7).

(iv) ASTM UOP539–97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, *see* § 98.7).

(v) ASTM D3176–89 (Reapproved 2002) Standard Practice Method for Ultimate Analysis of Coal and Coke (incorporated by reference, *see* § 98.7).

(vi) ASTM D5291–02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, *see* § 98.7).

(vii) ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, *see* § 98.7).

(viii) Methods 8031, 8021, or 8015 in ''Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,'' EPA Publication No. SW–846, Third Edition, September 1986, as amended by Update I, November 15, 1992.

(ix) Method 18 at 40 CFR part 60, appendix A–6.

(x) Performance Specification 9 in 40 CFR part 60, appendix B for continuous online gas analyzers. The 7-day calibration error test period must be completed prior to the effective date of the rule.

§ 98.245 Procedures for estimating missing data.

For missing feedstock flow rates, product flow rates, and carbon contents, use the same procedures as for missing flow rates and carbon contents for fuels as specified in § 98.35.

§ 98.246 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a), (b), or (c) of this section, as appropriate for each process unit.

(a) If you use the mass balance methodology in § 98.243(c), you must report the information specified in paragraphs (a)(1) through (a)(10) of this section for each type of petrochemical produced, reported by process unit.

(1) The petrochemical process unit ID number or other appropriate descriptor.

(2) The type of petrochemical produced, names of other products, and names of carbon-containing feedstocks.

(3) Annual CO_2 emissions calculated using Equation X–4 of this subpart.

(4) Each of the monthly volume, mass, and carbon content values used in Equations X–1 through X–3 of this subpart (i.e., the directly measured values, substitute values, or the calculated values based on other measured data such as tank levels or gas composition) and the molecular weights for gaseous feedstocks and products used in Equation X–1 of this subpart. Indicate whether you used the alternative to sampling and analysis specified in § 98.243(c)(4).

(5) Annual quantity of each type of petrochemical produced from each process unit (metric tons).

(6) Name of each method listed in § 98.244 used to determine a measured parameter (or description of manufacturer's recommended method).

(7) The dates and summarized results (e.g., percent calibration error) of the calibrations of each measurement device.

(8) Identification of each combustion unit that burned both process off-gas and supplemental fuel.

(9) If you comply with the alternative to sampling and analysis specified in § 98.243(c)(4), the amount of time during which off-specification product was produced, the volume or mass of off-specification product produced, and if applicable, the date of any process change that reduced the composition to less than 99.5 percent.

(10) You may elect to report the flow and carbon content of wastewater, and you may elect to report the carbon content of hydrocarbons in fugitive emissions and in process vents that are not controlled with a combustion device. These values may be estimated based on engineering analyses. These values are not to be used in the mass balance calculation.

(b) If you use CEMS to measure CO_2 emissions in accordance with § 98.243(b), then you must report the relevant information required under § 98.36 for the Tier 4 Calculation Methodology and the information listed in paragraphs (b)(1) through (b)(6) of this section.

(1) For CEMS used on stacks for stationary combustion units, report the relevant information required under § 98.36 for the Tier 4 calculation methodology.

(2) For CEMS used on stacks that are not used for stationary combustion units, report the information required under § 98.36(e)(2)(vi) and (vii).

(3) The petrochemical process unit ID or other appropriate descriptor, and the type of petrochemical produced.

(4) The CO_2 emissions from each stack and the combined CO_2 emissions from all stacks (except flare stacks) that handle process vent emissions and emissions from stationary combustion units that burn process off-gas for the petrochemical process unit. If a stationary combustion source serves multiple petrochemical process units or units other than the petrochemical process unit, estimate based on engineering judgment the fraction of fuel energy and emissions attributable to each petrochemical process unit.

(5) The CH_4 and N_2O emissions from each stack and the combined CH_4 and N_2O emissions from all stationary combustion units that burn process off-gas from the petrochemical process unit, the cumulative annual heat input used in Equation C–10 in § 98.33(c) of this subpart, and the annual flow of each fuel on which this heat input is based.

(6) ID or other appropriate descriptor of each stationary combustion unit that burns process off-gas.

(7) Information listed in § 98.256(e) of subpart Y of this part for each flare that burns process off-gas.

(8) Annual quantity of each type of petrochemical produced from each process unit (metric tons).

(c) If you comply with the combustion methodology specified in § 98.243(d), you must report under this subpart the information listed in paragraphs (c)(1) through (c)(4) of this section.

(1) For each stationary combustion unit that burns ethylene process off-gas (or group of stationary sources with a common pipe), the relevant information listed in § 98.36 for the selected Tier 3 or Tier 4 methodology. If a stationary combustion source serves multiple ethylene process units or units other than the ethylene process unit, estimate based on engineering judgment the fraction of fuel energy and emissions attributable to each ethylene process unit.

(2) Information listed in § 98.256(e) for each flare that burns ethylene process off-gas.

(3) Name and annual quantity of each feedstock.

(4) Annual quantity of each type of petrochemical produced from each process unit (metric tons).

§ 98.247 Records that must be retained.

In addition to the recordkeeping requirements in § 98.3(g), you must retain the records specified in paragraphs (a) through (c) of this section, as applicable.

(a) If you comply with the CEMS measurement methodology in § 98.243(b), then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in § 98.37.

(b) If you comply with the mass balance methodology in § 98.243(c), then you must retain records of the information listed in paragraphs (b)(1) through (b)(3) of this section.

(1) Results of feedstock or product composition determinations conducted in accordance with § 98.243(c)(4).

(2) Start and end times and calculated carbon contents for time periods when off-specification product is produced, if you comply with the alternative methodology in § 98.243(c)(4) for determining carbon content of feedstock or product.

(3) A part of the monitoring plan required under § 98.3(g)(5), record the estimated accuracy of measurement devices and the technical basis for these estimates.

(c) If you comply with the combustion methodology in § 98.243(d), then you must retain under this subpart the records required for the Tier 3 and/or Tier 4 Calculation Methodologies in § 98.37.

§ 98.248 Definitions.

Except as specified in this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Product, as used in § 98.243, means each of the following carbon-containing outputs from a process: the petrochemical, recovered byproducts, and liquid organic wastes that are not incinerated onsite. Product does not include process vent emissions, fugitive emissions, or wastewater.

Subpart Y—Petroleum Refineries

§ 98.250 Definition of source category.

(a) A petroleum refinery is any facility engaged in producing gasoline, gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt (bitumen) through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives, except as provided in paragraph (b) of this section.

(b) For the purposes of this subpart, facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation) are not petroleum refineries, regardless of the products produced.

(c) This source category consists of the following sources at petroleum refineries: Catalytic cracking units; fluid coking units; delayed coking units; catalytic reforming units; coke calcining units; asphalt blowing operations; blowdown systems; storage tanks; process equipment components (compressors, pumps, valves, pressure relief devices, flanges, and connectors) in gas service; marine vessel, barge, tanker truck, and similar loading operations; flares; sulfur recovery plants; and non-merchant hydrogen plants (i.e., hydrogen plants that are owned or under the direct control of the refinery owner and operator).

§ 98.251 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a petroleum refineries process and the facility meets the requirements of either § 98.2(a)(1) or (a)(2).

§ 98.252 GHGs to report.

You must report:

(a) CO_2, CH_4, and N_2O combustion emissions from stationary combustion units and from each flare. Calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C, except for CO_2 emissions from combustion of refinery fuel gas. For CO_2 emissions from combustion of fuel gas, use either equation C–5 in subpart C of this part or the Tier 4 methodology in subpart C of this part. You may aggregate units, monitor common stacks, or monitor common (fuel) pipes as provided in § 98.36(c) when calculating and reporting emissions from stationary combustion units.

(b) CO_2, CH_4, and N_2O coke burn-off emissions from each catalytic cracking unit, fluid coking unit, and catalytic reforming unit under this subpart.

(c) CO_2 emissions from sour gas sent off site for sulfur recovery operations under this subpart. You must follow the calculation methodologies from § 98.253(f) and the monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of this subpart.

(d) CO_2 process emissions from each on-site sulfur recovery plant under this subpart.

(e) CO_2, CH_4, and N_2O emissions from each coke calcining unit under this subpart.

(f) CO_2 and CH_4 emissions from asphalt blowing operations under this subpart.

(g) CH_4 emissions from equipment leaks, storage tanks, loading operations, delayed coking units, and uncontrolled blowdown systems under this subpart.

(h) CO_2, CH_4, and N_2O emissions from each process vent not specifically included in paragraphs (a) through (g) of this section under this subpart.

(i) CO_2 and CH_4 emissions from non-merchant hydrogen production under this subpart. You must follow the calculation methodologies, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart P of this part.

§ 98.253 Calculating GHG emissions.

(a) Calculate GHG emissions required to be reported in § 98.252(b) through (i) using the applicable methods in paragraphs (b) through (n) of this section.

(b) For flares, calculate GHG emissions according to the requirements in paragraphs (b)(1) through (b)(3) of this section.

(1) Calculate the CO_2 emissions according to the applicable requirements in paragraphs (b)(1)(i) through (b)(1)(iii) of this section.

(i) *Flow measurement.* If you have a continuous flow monitor on the flare, you must use the measured flow rates when the monitor is operational and the flow rate is within the calibrated range of the measurement device to calculate the flare gas flow. If you do not have a continuous flow monitor on the flare and for periods when the monitor is not operational or the flow rate is outside the calibrated range of the measurement device, you must use engineering calculations, company records, or similar estimates of volumetric flare gas flow.

(ii) *Heat value or carbon content measurement.* If you have a continuous higher heating value monitor or gas composition monitor on the flare or if you monitor these parameters at least weekly, you must use the measured heat value or carbon content value in calculating the CO_2 emissions from the flare using the applicable methods in paragraphs (b)(1)(ii)(A) and (b)(1)(ii)(B).

(A) If you monitor gas composition, calculate the CO_2 emissions from the flare using Equation Y–1 of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation Y–1 of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[\frac{44}{12} \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) \qquad \text{(Eq. Y-1)}$$

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (metric tons/year).

0.98 = Assumed combustion efficiency of a flare.

0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).

n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).

p = Measurement period index.

44 = Molecular weight of CO_2 (kg/kg-mole).

12 = Atomic weight of C (kg/kg-mole).

$(Flare)_p$ = Volume of flare gas combusted during measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term ''$(MW)_p$/MVC'' with ''1''.

$(MW)_p$ = Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

$(CC)_p$ = Average carbon content of the flare gas combusted during measurement period (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

(B) If you monitor heat content but do not monitor gas composition, calculate the CO_2 emissions from the flare using Equation Y–2 of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation Y–2 of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \sum_{p=1}^{n} \left[(Flare)_p \times (HHV)_p \times EmF \right] \qquad \text{(Eq. Y-2)}$$

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (metric tons/year).

0.98 = Assumed combustion efficiency of a flare.

0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).

n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).

p = Measurement period index.

$(Flare)_p$ = Volume of flare gas combusted during measurement period (million (MM) scf/period). If a mass flow meter is used, you must also measure molecular weight and convert the mass flow to a volumetric flow as follows: Flare[MMscf] = 0.000001 × Flare[kg] × MVC/$(MW)_p$, where MVC is the molar volume conversion factor (849.5 scf/kg-mole) and $(MW)_p$ is the average molecular weight of the flare gas combusted during measurement period (kg/kg-mole).

$(HHV)_p$ = Higher heating value for the flare gas combusted during measurement period (British thermal units per scf, Btu/scf = MMBtu/MMscf). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

EmF = Default CO_2 emission factor of 60 kilograms CO_2/MMBtu (HHV basis).

(iii) *Alternative to heat value or carbon content measurements.* If you do not measure the higher heating value or carbon content of the flare gas at least weekly, determine the quantity of gas discharged to the flare separately for periods of routine flare operation and for periods of start-up, shutdown, or malfunction, and calculate the CO_2 emissions as specified in paragraphs (b)(1)(iii)(A) through (b)(1)(iii)(C) of this section.

(A) For periods of start-up, shutdown, or malfunction, use engineering calculations and process knowledge to estimate the carbon content of the flared gas for each start-up, shutdown, or malfunction event exceeding 500,000 scf/day.

(B) For periods of normal operation, use the average heating value measured for the fuel gas for the heating value of the flare gas. If heating value is not measured, the heating value may be estimated from historic data or engineering calculations.

(C) Calculate the CO_2 emissions using Equation Y–3 of this section.

$$CO_2 = 0.98 \times 0.001 \times \left(Flare_{Norm} \times HHV \times EmF + \sum_{p=1}^{n} \left[\frac{44}{12} \times (Flare_{SSM})_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) \qquad \text{(Eq. Y-3)}$$

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (metric tons/year).

0.98 = Assumed combustion efficiency of a flare.

0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).

$Flare_{Norm}$ = Annual volume of flare gas combusted during normal operations from company records, (million (MM) standard cubic feet per year, MMscf/year).

HHV = Higher heating value for fuel gas or flare gas from company records (British thermal units per scf, Btu/scf = MMBtu/MMscf).

EmF = Default CO_2 emission factor for flare gas of 60 kilograms CO_2/MMBtu (HHV basis).

n = Number of start-up, shutdown, and malfunction events during the reporting year exceeding 500,000 scf/day.

p = Start-up, shutdown, and malfunction event index.

44 = Molecular weight of CO_2 (kg/kg-mole).

12 = Atomic weight of C (kg/kg-mole).

$(Flare_{SSM})_p$ = Volume of flare gas combusted during indexed start-up, shutdown, or malfunction event from engineering calculations, (scf/event).

$(MW)_p$ = Average molecular weight of the flare gas, from the analysis results or engineering calculations for the event (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

$(CC)_p$ = Average carbon content of the flare gas, from analysis results or engineering calculations for the event (kg C per kg flare gas).

(2) Calculate CH_4 using Equation Y–4 of this section.

$$CH_4 = \left(CO_2 \times \frac{EmF_{CH4}}{EmF} \right) + CO_2 \times \frac{0.02}{0.98} \times \frac{16}{44} \times f_{CH4} \qquad \text{(Eq. Y-4)}$$

Where:

CH_4 = Annual methane emissions from flared gas (metric tons CH_4/year).

CO_2 = Emission rate of CO_2 from flared gas calculated in paragraph (b)(1) of this section (metric tons/year).

EmF_{CH4} = Default CH_4 emission factor for ''PetroleumProducts'' from Table C–2 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CH_4/MMBtu).

EmF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis).

0.02/0.98 = Correction factor for flare combustion efficiency.

16/44 = Correction factor ratio of the molecular weight of CH_4 to CO_2.

f_{CH4} = Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane from measurement values or engineering calculations (kg C in methane in flare gas/kg C in flare gas); default is 0.4.

(3) Calculate N_2O emissions using Equation Y–5 of this section.

$$N_2O = \left(CO_2 \times \frac{EmF_{N2O}}{EmF} \right) \qquad \text{(Eq. Y-5)}$$

Where:

N_2O = Annual nitrous oxide emissions from flared gas (metric tons N_2O/year).

CO_2 = Emission rate of CO_2 from flared gas calculated in paragraph (b)(1) of this section (metric tons/year).

EmF_{N2O} = Default N_2O emission factor for ''PetroleumProducts'' from Table C–2 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg N_2O/MMBtu).

EmF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis).

(c) For catalytic cracking units and traditional fluid coking units, calculate the GHG emissions using the applicable methods described in paragraphs (c)(1) through (c)(5) of this section.

(1) If you operate and maintain a CEMS that measures CO_2 emissions according to subpart C of this part (General Stationary Fuel Combustion Sources), you must calculate and report CO_2 emissions as provided in paragraphs (c)(1)(i) and (c)(1)(ii) of this section. Other catalytic cracking units and traditional fluid coking units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Combustion Sources), or follow the requirements of paragraphs (c)(2) or (3) of this section.

(i) Calculate CO_2 emissions by following the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(ii) If a CO boiler or other post-combustion device is used, you must also calculate the CO_2 emissions from the fuel fired to the CO boiler or post-combustion device using the applicable methods for stationary combustion units in subpart C of this part. Calculate the process emissions from the catalytic cracking unit or fluid coking unit as the difference in the CO_2 CEMS emissions and the calculated combustion emissions associated with the CO boiler.

(2) For catalytic cracking units and fluid coking units with rated capacities greater than 10,000 barrels per stream day (bbls/sd) that do not use a continuous CO_2 CEMS for the final exhaust stack, you must continuously or no less frequently than hourly monitor the O_2, CO_2, and (if necessary) CO concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels and calculate the CO_2 emissions according to the requirements of paragraphs (c)(2)(i) through (c)(2)(iii) of this section:

(i) Calculate the CO_2 emissions from each catalytic cracking unit and fluid coking unit using Equation Y–6 of this section.

$$CO_2 = \sum_{p=1}^{n} \left[(Q_r)_p \times \frac{(\%CO_2 + \%CO)_p}{100\%} \times \frac{44}{MVC} \times 0.001 \right] \qquad \text{(Eq. Y-6)}$$

Where:

CO_2 = Annual CO_2 mass emissions (metric tons/year).

Q_r = Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels (dry standard cubic feet per hour, dscfh).

$\%CO_2$ = Hourly average percent CO_2 concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis).

%CO = Hourly average percent CO concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis). When there is no post-combustion device, assume %CO to be zero.

44 = Molecular weight of CO_2 (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

0.001 = Conversion factor (metric ton/kg).

n = Number of hours in calendar year.

(ii) Either continuously monitor the volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels or calculate the volumetric flow rate of this exhaust gas stream using Equation Y–7 of this section.

$$Q_r = \frac{\left(79 * Q_a + \left(100 - \%O_{oxy}\right) * Q_{oxy}\right)}{100 - \%CO_2 - \%CO - \%O_2} \qquad \text{(Eq. Y-7)}$$

Where:

Q_r = Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels (dscfh).

Q_a = Volumetric flow rate of air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh).

Q_{oxy} = Volumetric flow rate of oxygen enriched air to the fluid catalytic cracking unit regenerator or fluid coking unit burner as determined from control room instrumentation (dscfh).

$\%O_2$ = Hourly average percent oxygen concentration in exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis).
$\%O_{oxy}$ = O_2 concentration in oxygen enriched gas stream inlet to the fluid catalytic cracking unit regenerator or fluid coking unit burner based on oxygen purity specifications of the oxygen supply used for enrichment (percent by volume—dry basis).
$\%CO_2$ = Hourly average percent CO_2 concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis).
%CO = Hourly average percent CO concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis). When no auxiliary fuel is burned and a continuous CO monitor is not required under 40 CFR part 63 subpart UUU, assume %CO to be zero.

(iii) If you have a CO boiler that uses auxiliary fuels or combusts materials other than catalytic cracking unit or fluid coking unit exhaust gas, you must determine the CO_2 emissions resulting from the combustion of these fuels or other materials following the requirements in subpart C and report those emissions by following the requirements of subpart C of this part.

(3) For catalytic cracking units and fluid coking units with rated capacities of 10,000 barrels per stream day (bbls/sd) or less that do not use a continuous CO_2 CEMS for the final exhaust stack, comply with the requirements in paragraph (c)(3)(i) of this section or paragraphs (c)(3)(ii) and (c)(3)(iii) of this section, as applicable.

(i) If you continuously or no less frequently than daily monitor the O_2, CO_2, and (if necessary) CO concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels, you must calculate the CO_2 emissions according to the requirements of paragraphs (c)(2)(i) through (c)(2)(iii) of this section, except that daily averages are allowed and the summation can be performed on a daily basis.

(ii) If you do not monitor at least daily the O_2, CO_2, and (if necessary) CO concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels, calculate the CO_2 emissions from each catalytic cracking unit and fluid coking unit using Equation Y–8 of this section.

$$CO_2 = Q_{unit} \times (CBF \times 0.001) \times CC \times \frac{44}{12} \qquad \text{(Eq. Y-8)}$$

Where:
CO_2 = Annual CO_2 mass emissions (metric tons/year).
Q_{unit} = Annual throughput of unit from company records (barrels (bbls) per year, bbl/yr).
CBF = Coke burn-off factor from engineering calculations (kg coke per barrel of feed); default for catalytic cracking units = 7.3; default for fluid coking units = 11.
0.001 = Conversion factor (metric ton/kg).
CC = Carbon content of coke based on measurement or engineering estimate (kg C per kg coke); default = 0.94.
44/12 = Ratio of molecular weight of CO_2 to C (kg CO_2 per kg C).

(iii) If you have a CO boiler that uses auxiliary fuels or combusts materials other than catalytic cracking unit or fluid coking unit exhaust gas, you must determine the CO_2 emissions resulting from the combustion of these fuels or other materials following the requirements in subpart C of this part (General Stationary Fuel Combustion Sources) and report those emissions by following the requirements of subpart C of this part.

(4) Calculate CH_4 emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation Y–9 of this section.

$$CH_4 = \left(CO_2 * \frac{EmF_2}{EmF_1} \right) \qquad \text{(Eq. Y-9)}$$

Where:
CH_4 = Annual methane emissions from coke burn-off (metric tons CH_4/year).
CO_2 = Emission rate of CO_2 from coke burn-off calculated in paragraphs (c)(1), (c)(2), (e)(1), (e)(2), (g)(1), or (g)(2) of this section, as applicable (metric tons/year).
EmF_1 = Default CO_2 emission factor for petroleum coke from Table C–1 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CO_2/MMBtu).
EmF_2 = Default CH_4 emission factor for ‘‘PetroleumProducts’’ from Table C–2 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CH_4/MMBtu).

(5) Calculate N_2O emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation Y–10 of this section.

$$N_2O = \left(CO_2 * \frac{EmF_3}{EmF_1} \right) \qquad \text{(Eq. Y-10)}$$

Where:
N_2O = Annual nitrous oxide emissions from coke burn-off (mt N_2O/year).
CO_2 = Emission rate of CO_2 from coke burn-off calculated in paragraphs (c)(1), (c)(2), (e)(1), (e)(2), (g)(1), or (g)(2) of this section, as applicable (metric tons/year).
EmF_1 = Default CO_2 emission factor for petroleum coke from Table C–1 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CO_2/MMBtu).
EmF_3 = Default N_2O emission factor for ‘‘PetroleumProducts’’ from Table C–2 of subpart C of this part (kg N_2O/MMBtu).

(d) For fluid coking units that use the flexicoking design, the GHG emissions from the resulting use of the low value fuel gas must be accounted for only once. Typically, these emissions will be accounted for using the methods described in subpart C of this part (General Stationary Fuel Combustion Sources). Alternatively, you may use the methods in paragraph (c) of this section provided that you do not otherwise account for the subsequent combustion of this low value fuel gas.

(e) For catalytic reforming units, calculate the CO_2 emissions using the applicable methods described in paragraphs (e)(1) through (e)(3) of this section and calculate the CH_4 and N_2O emissions using the methods described in paragraphs (c)(4) and (c)(5) of this section, respectively.

(1) If you operate and maintain a CEMS that measures CO_2 emissions according to subpart C of this part (General Stationary Fuel Combustion Sources), you must calculate CO_2 emissions as provided in paragraphs (c)(1)(i) and (c)(1)(ii) of this section. Other catalytic reforming units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part, or follow the requirements of paragraph (e)(2) or (e)(3) of this section.

(2) If you continuously or no less frequently than daily monitor the O_2, CO_2, and (if necessary) CO concentrations in the exhaust stack from the catalytic reforming unit catalyst regenerator prior to the combustion of other fossil fuels, you must calculate the CO_2 emissions according to the requirements of paragraphs (c)(2)(i) through (c)(2)(iii) of this section.

(3) Calculate CO_2 emissions from the catalytic reforming unit catalyst regenerator using Equation Y–11 of this section.

$$CO_2 = \sum_{1}^{n} \left[\left(CB_Q \right)_n \times CC \times \frac{44}{12} \times 0.001 \right] \qquad \text{(Eq. Y-11)}$$

Where:

CO_2 = Annual CO_2 emissions (metric tons/year).

CB_Q = Coke burn-off quantity per regeneration cycle from engineering estimates (kg coke/cycle).

n = Number of regeneration cycles in the calendar year.

CC = Carbon content of coke based on measurement or engineering estimate (kg C per kg coke); default = 0.94.

44/12 = Ratio of molecular weight of CO_2 to C (kg CO_2 per kg C).

0.001 = Conversion factor (metric ton/kg).

(f) For on-site sulfur recovery plants, calculate and report CO_2 process emissions from sulfur recovery plants according to the requirements in paragraphs (f)(1) through (f)(5) of this section. Combustion emissions from the sulfur recovery plant (e.g., from fuel combustion in the Claus burner or the tail gas treatment incinerator) must be reported under subpart C of this part (General Stationary Fuel Combustion Sources). For the purposes of this subpart, the sour gas stream for which monitoring is required according to paragraphs (f)(2) through (f)(5) of this section is not considered a fuel.

(1) If you operate and maintain a CEMS that measures CO_2 emissions according to subpart C of this part, you must calculate CO_2 emissions under this subpart by following the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). You must monitor fuel use in the Claus burner, tail gas incinerator, or other combustion sources that discharge via the final exhaust stack from the sulfur recovery plant and calculate the combustion emissions from the fuel use according to subpart C of this part. Calculate the process emissions from the sulfur recovery plant as the difference in the CO_2 CEMS emissions and the calculated combustion emissions associated with the sulfur recovery plant final exhaust stack. Other sulfur recovery plants must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C, or follow the requirements of paragraphs (f)(2) through (f)(5) of this section.

(2) Flow measurement. If you have a continuous flow monitor on the sour gas feed to the sulfur recovery plant, you must use the measured flow rates when the monitor is operational to calculate the sour gas flow rate. If you do not have a continuous flow monitor on the sour gas feed to the sulfur recovery plant, you must use engineering calculations, company records, or similar estimates of volumetric sour gas flow.

(3) Carbon content. If you have a continuous gas composition monitor capable of measuring carbon content on the sour gas feed to the sulfur recovery plant or if you monitor gas composition for carbon content on a routine basis, you must use the measured carbon content value. Alternatively, you may develop a site-specific carbon content factor using limited measurement data or engineering estimates or use the default factor of 0.20.

(4) Calculate the CO_2 emissions from each sulfur recovery plant using Equation Y–12 of this section.

$$CO_2 = F_{SG} * \frac{44}{MVC} * MF_C * 0.001 \qquad \text{(Eq. Y-12)}$$

Where:

CO_2 = Annual CO_2 emissions (metric tons/year).

F_{SG} = Volumetric flow rate of sour gas feed (including sour water stripper gas) to the sulfur recovery plant (scf/year).

44 = Molecular weight of CO_2 (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

MF_C = Mole fraction of carbon in the sour gas to the sulfur recovery plant (kg-mole C/kg-mole gas); default = 0.20.

0.001 = Conversion factor, kg to metric tons.

(5) If tail gas is recycled to the front of the sulfur recovery plant and the recycled flow rate and carbon content is included in the measured data under paragraphs (f)(2) and (f)(3) of this section, respectively, then the annual CO_2 emissions calculated in paragraph (f)(4) of this section must be corrected to avoid double counting these emissions. You may use engineering estimates to perform this correction or assume that the corrected CO_2 emissions are 95 percent of the uncorrected value calculated using Equation Y–12 of this section.

(g) For coke calcining units, calculate GHG emissions according to the applicable provisions in paragraphs (g)(1) through (g)(3) of this section.

(1) If you operate and maintain a CEMS that measures CO_2 emissions according to subpart C of this part, you must calculate and report CO_2 emissions under this subpart by following the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). You must monitor fuel use in the coke calcining unit that discharges via the final exhaust stack from the coke calcining unit and calculate the combustion emissions from the fuel use according to subpart C of this part. Calculate the process emissions from the coke calcining unit as the difference in the CO_2 CEMS emissions and the calculated combustion emissions associated with the coke calcining unit final exhaust stack. Other coke calcining units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part, or follow the requirements of paragraph (g)(2) of this section.

(2) Calculate the CO_2 emissions from the coke calcining unit using Equation Y–13 of this section.

$$CO_2 = \frac{44}{12} * \left(M_{in} * CC_{GC} - \left(M_{out} + M_{dust}\right) * CC_{MPC}\right) \qquad \text{(Eq. Y-13)}$$

Where:

CO_2 = Annual CO_2 emissions (metric tons/year).

M_{in} = Annual mass of green coke fed to the coke calcining unit from facility records (metric tons/year).

CC_{GC} = Average mass fraction carbon content of green coke from facility measurement data (metric ton carbon/metric ton green coke).

M_{out} = Annual mass of marketable petroleum coke produced by the coke calcining unit from facility records (metric tons petroleum coke/year).

M_{dust} = Annual mass of petroleum coke dust collected in the dust collection system of the coke calcining unit from facility records (metric ton petroleum coke dust/year).

CC_{MPC} = Average mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit from facility measurement data (metric ton carbon/metric ton petroleum coke).

44 = Molecular weight of CO_2 (kg/kg-mole).

12 = Atomic weight of C (kg/kg-mole).

(3) For all coke calcining units, use the CO_2 emissions from the coke calcining unit calculated in paragraphs (g)(1) or (g)(2), as applicable, and calculate CH_4 using the methods described in paragraph (c)(4) of this section and N_2O emissions using the methods described in paragraph (c)(5) of this section.

(h) For asphalt blowing operations, calculate GHG emissions according to the requirements in paragraph (j) of this section or according to the applicable provisions in paragraphs (h)(1) and (h)(2) of this section.

(1) For uncontrolled asphalt blowing operations or asphalt blowing operations controlled by vapor scrubbing, calculate CO_2 and CH_4 emissions using Equations Y–14 and Y–15 of this section, respectively.

$$CO_2 = \left(Q_{AB} \times EF_{AB,CO2}\right) \qquad \text{(Eq. Y-14)}$$

Where:

CO_2 = Annual CO_2 emissions from uncontrolled asphalt blowing (metric tons CO_2/year).

Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).

$EF_{AB,CO2}$ = Emission factor for CO_2 from uncontrolled asphalt blowing from facility-specific test data (metric tons CO_2/MMbbl asphalt blown); default = 1,100.

$$CH_4 = \left(Q_{AB} \times EF_{AB,CH4}\right) \qquad \text{(Eq. Y-15)}$$

Where:

CH_4 = Annual methane emissions from uncontrolled asphalt blowing (metric tons CH_4/year).

Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).

EF_{AB,CH_4} = Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (metric tons CH_4/MMbbl asphalt blown); default = 580.

(2) For asphalt blowing operations controlled by thermal oxidizer or flare, calculate CO_2 and CH_4 emissions using Equations Y–16 and Y–17 of this section, respectively, provided these emissions are not already included in the flare emissions calculated in paragraph (b) of this section or in the stationary combustion unit emissions required under subpart C of this part (General Stationary Fuel Combustion Sources).

$$CO_2 = 0.98 \times \left(Q_{AB} \times CEF_{AB} \times \frac{44}{12}\right) \qquad \text{(Eq. Y-16)}$$

Where:

CO_2 = Annual CO_2 emissions from controlled asphalt blowing (metric tons CO_2/year).

0.98 = Assumed combustion efficiency of thermal oxidizer or flare.

Q_{AB} = Quantity of asphalt blown (MMbbl/year).

CEF_{AB} = Carbon emission factor from asphalt blowing from facility-specific test data (metric tons C/MMbbl asphalt blown); default = 2,750.

44 = Molecular weight of CO_2 (kg/kg-mole).

12 = Atomic weight of C (kg/kg-mole).

$$CH_4 = 0.02 \times \left(Q_{AB} \times EF_{AB,CH4}\right) \qquad \text{(Eq. Y-17)}$$

Where:

CH_4 = Annual methane emissions from controlled asphalt blowing (metric tons CH_4/year).

0.02 = Fraction of methane uncombusted in thermal oxidizer or flare based on assumed 98% combustion efficiency.

Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).

EF_{AB,CH_4} = Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (metric tons CH_4/MMbbl asphalt blown); default = 580.

(i) For delayed coking units, calculate the CH_4 emissions from the depressurization of the coking unit vessel (i.e., the ‘‘coke drum’’) to atmosphere using either of the methods provided in paragraphs (i)(1) or (i)(2), provided no water or steam is added to the vessel once it is vented to the atmosphere. You must use the method in paragraph (i)(1) of this section if you add water or steam to the vessel after it is vented to the atmosphere.

(1) Use the process vent method in paragraph (j) of this section and also calculate the CH_4 emissions from the subsequent opening of the vessel for coke cutting operations using Equation Y–18 of this section. If you have coke drums or vessels of different dimensions, use Equation Y–18 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH_4 emissions for all delayed coking units.

$$CH_4 = \left(N \times H \times \frac{(P_{CV} + 14.7)}{14.7} \times f_{void} \times \frac{\pi \times D^2}{4} \times \frac{16}{MVC} \times MF_{CH4} \times 0.001\right) \qquad \text{(Eq. Y-18)}$$

Where:

CH_4 = Annual methane emissions from the delayed coking unit vessel opening (metric ton/year).

N = Cumulative number of vessel openings for all delayed coking unit vessels of the same dimensions during the year.

H = Height of coking unit vessel (feet).

P_{CV} = Gauge pressure of the coking vessel when opened to the atmosphere prior to coke cutting or, if the alternative method provided in paragraph (i)(2) of this section is used, gauge pressure of the coking vessel when depressurization gases are first routed to the atmosphere (pounds per square inch gauge, psig).

14.7 = Assumed atmospheric pressure (pounds per square inch, psi).

f_{void} = Volumetric void fraction of coking vessel prior to steaming (cf gas/cf of vessel); default = 0.6.

D = Diameter of coking unit vessel (feet).

16 = Molecular weight of CH_4 (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

MF_{CH_4} = Mole fraction of methane in coking vessel gas (kg-mole CH_4/kg-mole gas, wet basis); default value is 0.01.

0.001 = Conversion factor (metric ton/kg).

(2) Calculate the CH_4 emissions from the depressurization vent and subsequent opening of the vessel for coke cutting operations using Equation Y–18 of this section and the pressure of the coking vessel when the depressurization gases are first routed to the atmosphere. If you have coke drums or vessels of different dimensions, use Equation Y–18 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH_4 emissions for all delayed coking units.

(j) For each process vent not covered in paragraphs (a) through (i) of this section that can be reasonably expected to contain greater than 2 percent by volume CO_2 or greater than 0.5 percent by volume of CH_4 or greater than 0.01 percent by volume (100 parts per million) of N_2O, calculate GHG emissions using the Equation Y–19 of this section. You must use Equation Y–19 of this section for catalytic reforming unit depressurization and purge vents when methane is used as the purge gas or if you elected this method as an alternative to the methods in paragraphs (h)(1) or (h)(2) of this section.

$$E_x = \sum_{p=1}^{N}\left((VR)_p \times (MF_x)_p \times \frac{MW_x}{MVC} \times (VT)_p \times 0.001\right) \qquad \text{(Eq. Y-19)}$$

Where:

E_x = Annual emissions of each GHG from process vent (metric ton/yr).

N = Number of venting events per year.

P = Index of venting events.

$(VR)_p$ = Average volumetric flow rate of process gas during the event (scf per hour).

$(MF_x)_p$ = Mole fraction of GHG x in process vent during the event (kg-mol of GHG x/kg-mol vent gas).

MW_x = Molecular weight of GHG x (kg/kg-mole); use 44 for CO_2 or N_2O and 16 for CH_4.

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

$(VT)_p$ = Venting time for the event, (hours).

0.001 = Conversion factor (metric ton/kg).

(k) For uncontrolled blowdown systems, you must either use the methods for process vents in paragraph (j) of this section or calculate CH_4 emissions using Equation Y–20 of this section. Blowdown systems where the uncondensed gas stream is routed to a flare or similar control device is considered to be controlled and is not required to estimate emissions under this paragraph (k).

$$CH_4 = \left(Q_{\mathrm{Re}_f} \times EF_{BD} \times \frac{16}{MVC} \times 0.001\right) \qquad \text{(Eq. Y-20)}$$

Where:

CH_4 = Methane emission rate from blowdown systems (mt CH_4/year).

Q_{Ref} = Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).

EF_{BD} = Methane emission factor for uncontrolled blown systems (scf CH_4/MMbbl); default is 137,000.

16 = Molecular weight of CH_4 (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

0.001 = Conversion factor (metric ton/kg).

(l) For equipment leaks, calculate CH_4 emissions using the method specified in either paragraph (l)(1) or (l)(2) of this section.

(1) Use process-specific methane composition data (from measurement data or process knowledge) and any of the emission estimation procedures provided in the Protocol for Equipment Leak Emissions Estimates (EPA–453/R–95–017, NTIS PB96–175401).

(2) Use Equation Y–21 of this section.

$$CH_4 = \left(0.4 \times N_{CD} + 0.2 \times N_{PU1} + 0.1 \times N_{PU2} + 4.3 \times N_{H2} + 6 \times N_{FGS}\right) \qquad \text{(Eq. Y-21)}$$

Where:

CH_4 = Annual methane emissions from equipment leaks (metric tons/year).

N_{CD} = Number of atmospheric crude oil distillation columns at the facility.

N_{PU1} = Cumulative number of catalytic cracking units, coking units (delayed or fluid), hydrocracking, and full-range distillation columns (including depropanizer and debutanizer distillation columns) at the facility.

N_{PU2} = Cumulative number of hydrotreating/hydrorefining units, catalytic reforming units, and visbreaking units at the facility.

N_{H2} = Total number of hydrogen plants at the facility.

N_{FGS} = Total number of fuel gas systems at the facility.

(m) For storage tanks, except as provided in paragraph (m)(3) of this section, calculate CH_4 emissions using the applicable methods in paragraphs (m)(1) and (m)(2) of this section.

(1) For storage tanks other than those processing unstabilized crude oil, you must either calculate CH_4 emissions from storage tanks that have a vapor-phase methane concentration of 0.5 volume percent or more using tank-specific methane composition data (from measurement data or product knowledge) and the AP–42 emission

estimation methods provided in Section 7.1 of the AP–42: ''Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources'', including TANKS Model (Version 4.09D) or similar programs, or estimate CH_4 emissions from storage tanks using Equation Y–22 of this section.

$$CH_4 = \left(0.1 \times Q_{\mathrm{Ref}}\right) \qquad \text{(Eq. Y-22)}$$

Where:

CH_4 = Annual methane emissions from storage tanks (metric tons/year).

0.1 = Default emission factor for storage tanks (metric ton CH_4/MMbbl).

Q_{Ref} = Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).

(2) For storage tanks that process unstabilized crude oil, calculate CH_4 emissions from the storage of unstabilized crude oil using either tank-specific methane composition data (from measurement data or product knowledge) and direct measurement of the gas generation rate or by using Equation Y–23 of this section.

$$CH_4 = \left(995{,}000 \times Q_{un} \times \Delta P\right) \times MF_{CH4} \times \frac{16}{MVC} \times 0.001 \qquad \text{(Eq. Y-23)}$$

Where:

CH_4 = Annual methane emissions from storage tanks (metric tons/year).

Q_{un} = Quantity of unstabilized crude oil received at the facility (MMbbl/year).

ΔP = Pressure differential from the previous storage pressure to atmospheric pressure (pounds per square inch, psi).

MF_{CH4} = Mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tank from facility measurements (kg-mole CH_4/kg-mole gas); use 0.27 as a default if measurement data are not available.

995,000 = Correlation Equation factor (scf gas per MMbbl per psi).

16 = Molecular weight of CH_4 (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

0.001 = Conversion factor (metric ton/kg).

(3) You do not need to calculate CH_4 emissions from storage tanks that meet any of the following descriptions:

(i) Units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships;

(ii) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;

(iii) Bottoms receivers or sumps;

(iv) Vessels storing wastewater; or

(v) Reactor vessels associated with a manufacturing process unit.

(n) For crude oil, intermediate, or product loading operations for which the equilibrium vapor-phase concentration of methane is 0.5 volume percent or more, calculate CH_4 emissions from loading operations using product-specific, vapor-phase methane composition data (from measurement data or process knowledge) and the emission estimation procedures provided in Section 5.2 of the AP–42: ''Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources.'' For loading operations in which the equilibrium vapor-phase concentration of methane is less than 0.5 volume percent, you may assume zero methane emissions.

§ 98.254 Monitoring and QA/QC requirements.

(a) Fuel flow meters, gas composition monitors, and heating value monitors associated with stationary combustion sources must follow the monitoring and QA/QC requirements in § 98.34.

(b) All flow meters, gas composition monitors, and heating value monitors that are used to provide data for the GHG emissions calculations in this subpart for sources other than stationary combustion sources shall be calibrated according to the procedures in the applicable methods specified in paragraphs (c) through (e) of this section, the procedures specified by the manufacturer, or §§ 98.3(i). Recalibrate each flow meter either biennially (every two years) or at the minimum frequency specified by the manufacturer. Recalibrate each gas composition monitor and heating value monitor either annually or at the minimum frequency specified by the manufacturer.

(c) For flare or sour gas flow meters, operate and maintain the flow meter using any of the following methods, a method published by a consensus-based standards organization (e.g., ASTM, API, etc.) or follow the procedures specified by the flow meter manufacturer. Flow meters must have a rated accuracy of ±5 percent or lower.

(1) ASME MFC–3M–2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, *see* § 98.7).

(2) ASME MFC–4M–1986 (Reaffirmed 1997) Measurement of Gas Flow by Turbine Meters (incorporated by reference, see § 98.7).

(3) ASME MFC–6M–1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, *see* § 98.7).

(4) ASME MFC–7M–1987 (Reaffirmed 1992) Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, *see* § 98.7).

(5) ASME MFC–11M–2006 Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters (incorporated by reference, *see* § 98.7).

(6) ASME MFC–14M–2003 Measurement of Fluid Flow Using Small Bore Precision Orifice Meters (incorporated by reference, *see* § 98.7).

(7) ASME MFC–18M–2001 Measurement of Fluid Flow Using Variable Area Meters (incorporated by reference, *see* § 98.7).

(8) AGA Report No. 11 Measurement of Natural Gas by Coriolis Meter (2003) (incorporated by reference, *see* § 98.7).

(d) Determine flare gas composition using any of the following methods.

(1) Method 18 at 40 CFR part 60, appendix A–6.

(2) ASTM D1945–03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, *see* § 98.7).

(3) ASTM D1946–90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, *see* § 98.7).

(4) GPA 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, *see* § 98.7).

(5) UOP539–97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, *see* § 98.7).

(e) Determine flare gas higher heating value using any of the following methods.

(1) ASTM D4809–06 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) (incorporated by reference, *see* § 98.7).

(2) ASTM D240–02 (Reapproved 2007) Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (incorporated by reference, *see* § 98.7).

(3) ASTM D1826–94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter (incorporated by reference, *see* § 98.7).

(4) ASTM D3588–98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (incorporated by reference, *see* § 98.7).

(5) ASTM D4891–89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (incorporated by reference, *see* § 98.7).

(f) For exhaust gas flow meters used to comply with the requirements in § 98.253(c)(2)(ii), install, operate, calibrate, and maintain exhaust gas flow meter according to the requirements in 40 CFR 63.1572(c) or according to the following requirements.

(1) Locate the flow meter(s) and other necessary equipment such as straightening vanes in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(2) Use a flow rate meter with an accuracy within ± 5 percent.

(3) Use a continuous monitoring system capable of correcting for the temperature, pressure, and moisture content to output flow in dry standard cubic feet (standard conditions as defined in § 98.6).

(4) Install, operate, and maintain each continuous monitoring system according to the manufacturer's specifications and requirements.

(g) For exhaust gas $CO_2/CO/O_2$ composition monitors used to comply with the requirements in § 98.253(c)(2), install, operate, calibrate, and maintain exhaust gas composition monitors according to the requirements in 40 CFR 60.105a(b)(2) or 40 CFR 63.1572(a) or according to the manufacturer's specifications and requirements.

(h) Determine the mass of petroleum coke as required by Equation Y–13 of this subpart using mass measurement equipment meeting the requirements for commercial weighing equipment as described in Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices, NIST Handbook 44 (2009) (incorporated by reference, see § 98.7). Calibrate the measurement device according to the procedures specified by the method, the procedures specified by the manufacturer, or § 98.3(i). Recalibrate either biennially or at the minimum frequency specified by the manufacturer.

(i) Determine the carbon content of petroleum coke as required by Equation Y–13 of this subpart using any one of the following methods. Calibrate the measurement device according to procedures specified by the method or procedures specified by the measurement device manufacturer.

(1) ASTM D3176–89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, *see* § 98.7).

(2) ASTM D5291–02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, *see* § 98.7).

(3) ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, *see* § 98.7).

(j) Determine the quantity of petroleum process streams using company records. These quantities include the quantity of asphalt blown, quantity of crude oil plus the quantity of intermediate products received from off site, and the quantity of unstabilized crude oil received at the facility.

(k) The owner or operator shall document the procedures used to ensure the accuracy of the estimates of fuel usage, gas composition, and heating value including but not limited to calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

(l) All CO_2 CEMS and flow rate monitors used for direct measurement of GHG emissions must comply with the QA procedures in § 98.34(c).

§ 98.255 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., concentrations, flow rates, fuel heating values, carbon content values). Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For stationary combustion sources, use the missing data procedures in subpart C of this part.

(b) For each missing value of the heat content, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the ''after'' value is not obtained by the end of the reporting year, you may use the ''before'' value for the missing data substitution. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(c) For missing CO_2, CO, O_2, CH_4, or N_2O concentrations, gas flow rate, and percent moisture, the substitute data values shall be the best available estimate(s) of the parameter(s), based on all available process data (e.g., processing rates, operating hours, etc.). The owner or operator shall document and keep records of the procedures used for all such estimates.

(d) For hydrogen plants, use the missing data procedures in subpart P of this part.

§ 98.256 Data reporting requirements.

In addition to the reporting requirements of § 98.3(c), you must report the information specified in paragraphs (a) through (q) of this section.

(a) For combustion sources, follow the data reporting requirements under subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For hydrogen plants, follow the data reporting requirements under subpart P of this part (Hydrogen Production).

(c) [Reserved]

(d) [Reserved]

(e) For flares, owners and operators shall report:

(1) The flare ID number (if applicable).

(2) A description of the type of flare (steam assisted, air-assisted).

(3) A description of the flare service (general facility flare, unit flare, emergency only or back-up flare).

(4) The calculated CO_2, CH_4, and N_2O annual emissions for each flare, expressed in metric tons of each pollutant emitted.

(5) A description of the method used to calculate the CO_2 emissions for each flare (e.g., reference section and equation number).

(6) If you use Equation Y–1 of this subpart, the annual volume of flare gas combusted (in scf/year) and the annual average molecular weight (in kg/kg-mole) and carbon content of the flare gas (in kg carbon per kg flare gas).

(7) If you use Equation Y–2 of this subpart, the annual volume of flare gas combusted (in million (MM) scf/year) and the annual average higher heating value of the flare gas (in MMBtu per MMscf).

(8) If you use Equation Y–3 of this subpart, the annual volume of flare gas combusted (in MMscf/year) during

normal operations, the annual average higher heating value of the flare gas (in MMBtu/MMscf), the number of SSM events exceeding 500,000 scf/day, and the volume of gas flared (in scf/event) and the average molecular weight (in kg/kg-mole) and carbon content of the flare gas (in kg carbon per kg flare) for each SSM event over 500,000 scf/day.

(9) The fraction of carbon in the flare gas contributed by methane used in Equation Y–4 of this subpart and the basis for its value.

(f) For catalytic cracking units, traditional fluid coking units, and catalytic reforming units, owners and operators shall report:

(1) The unit ID number (if applicable).

(2) A description of the type of unit (fluid catalytic cracking unit, thermal catalytic cracking unit, traditional fluid coking unit, or catalytic reforming unit).

(3) Maximum rated throughput of the unit, in bbl/stream day.

(4) The calculated CO_2, CH_4, and N_2O annual emissions for each unit, expressed in metric tons of each pollutant emitted.

(5) A description of the method used to calculate the CO_2 emissions for each unit (e.g., reference section and equation number).

(6) If you use a CEMS, the relevant information required under § 98.36(e)(2)(vi) for the Tier 4 Calculation Methodology, the CO_2 annual emissions as measured by the CEMS (unadjusted to remove CO_2 combustion emissions associated with a CO boiler, if present) and the process CO_2 emissions as calculated according to § 98.253(c)(1)(ii). Report the CO_2 annual emissions associated with fuel combustion under subpart C of this part (General Stationary Fuel Combustion Sources).

(7) If you use Equation Y–6 of this subpart, the annual average exhaust gas flow rate, $\%CO_2$, and %CO.

(8) If you use Equation Y–7 of this subpart, the annual average flow rate of inlet air and oxygen-enriched air, $\%O_2$, $\%O_{oxy}$, $\%CO_2$, and %CO.

(9) If you use Equation Y–8 of this subpart, the coke burn-off factor, annual throughput of unit, and the average carbon content of coke and the basis for the value.

(10) Indicate whether you use a measured value, a unit-specific emission factor, or a default emission factor for CH_4 emissions. If you use a unit-specific emission factor for CH_4, report the units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor.

(11) Indicate whether you use a measured value, a unit-specific emission factor, or a default emission factor for N_2O emissions. If you use a unit-specific emission factor for N_2O, report the units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor.

(12) If you use Equation Y–11 of this subpart, the number of regeneration cycles during the reporting year, the average coke burn-off quantity per cycle, and the average carbon content of the coke.

(g) For fluid coking unit of the flexicoking type, the owner or operator shall report:

(1) The unit ID number (if applicable).

(2) A description of the type of unit.

(3) Maximum rated throughput of the unit, in bbl/stream day.

(4) Indicate whether the GHG emissions from the low heat value gas are accounted for in subpart C of this part or § 98.253(c).

(5) If the GHG emissions for the low heat value gas are calculated at the flexicoking unit, also report the calculated annual CO_2, CH_4, and N_2O emissions for each unit, expressed in metric tons of each pollutant emitted, and the applicable equation input parameters specified in paragraphs (f)(7) through (f)(11) of this section.

(h) For sulfur recovery plants and for emissions from sour gas sent off-site for sulfur recovery, the owner and operator shall report:

(1) The plant ID number (if applicable).

(2) Maximum rated throughput of each independent sulfur recovery plant, in metric tons sulfur produced/stream day.

(3) The calculated CO_2 annual emissions for each sulfur recovery plant, expressed in metric tons. The calculated annual CO_2 emissions from sour gas sent off-site for sulfur recovery, expressed in metric tons.

(4) If you use Equation Y–12 of this subpart, the annual volumetric flow to the sulfur recovery plant (in scf/year) and the annual average mole fraction of carbon in the sour gas (in kg-mole C/kg-mole gas).

(5) If you recycle tail gas to the front of the sulfur recovery plant, indicate whether the recycled flow rate and carbon content are included in the measured data under § 98.253(f)(2) and (3). Indicate whether a correction for CO_2 emissions in the tail gas was used in Equation Y–12. If so, then report the value of the correction, the annual volume of recycled tail gas (in scf/year) and the annual average mole fraction of carbon in the tail gas (in kg-mole C/kg-mole gas). Indicate whether you used the default (95%) or a unit specific correction, and if used, report the approach used.

(6) If you use a CEMS, the relevant information required under § 98.36(e)(2)(vi) for the Tier 4 Calculation Methodology, the CO_2 annual emissions as measured by the CEMS and the annual process CO_2 emissions calculated according to § 98.253(f)(1). Report the CO_2 annual emissions associated with fuel combustion subpart C of this part (General Stationary Fuel Combustion Sources).

(i) For coke calcining units, the owner and operator shall report:

(1) The unit ID number (if applicable).

(2) Maximum rated throughput of the unit, in metric tons coke calcined/stream day.

(3) The calculated CO_2, CH_4, and N_2O annual emissions for each unit, expressed in metric tons of each pollutant emitted.

(4) A description of the method used to calculate the CO_2 emissions for each unit (e.g., reference section and equation number).

(5) If you use Equation Y–13 of this subpart, annual mass and carbon content of green coke fed to the unit, the annual mass and carbon content of marketable coke produced, and the annual mass of coke dust collected in dust collection systems.

(6) If you use a CEMS, the relevant information required under § 98.36(e)(2)(vi) for the Tier 4 Calculation Methodology, the CO_2 annual emissions as measured by the CEMS and the annual process CO_2 emissions calculated according to § 98.253(g)(1). Report the CO_2 annual emissions associated with fuel combustion under subpart C of this part (General Stationary Fuel Combustion Sources).

(7) Indicate whether you use a measured value, a unit-specific emission factor or a default for CH_4 emissions. If you use a unit-specific emission factor for CH_4, the unit-specific emission factor for CH_4, the units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor.

(8) If you use a site-specific emission factor in Equation Y–10 of this subpart, the site-specific emission factor and the basis of the factor.

(j) For asphalt blowing operations, the owner or operator shall report:

(1) The unit ID number (if applicable).

(2) The quantity of asphalt blown (in Million bbl) at the facility in the reporting year.

(3) The type of control device used to reduce methane (and other organic) emissions from the unit.

(4) The calculated annual CO_2 and CH_4 emissions for each unit, expressed in metric tons of each pollutant emitted.

(5) If you use Equation Y–14 of this subpart, the CO_2 emission factor used and the basis for the value.

(6) If you use Equation Y–15 of this subpart, the CH_4 emission factor used and the basis for the value.

(7) If you use Equation Y–16 of this subpart, the carbon emission factor used and the basis for the value.

(8) If you use Equation Y–17 of this subpart, the CH_4 emission factor used and the basis for the value.

(k) For delayed coking units, the owner or operator shall report:

(1) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for all delayed coking units at the facility.

(2) A description of the method used to calculate the CH_4 emissions for each unit (e.g., reference section and equation number).

(3) The total number of delayed coking units at the facility, the total number of delayed coking drums at the facility, and for each coke drum or vessel: the dimensions, the typical gauge pressure of the coking drum when first vented to the atmosphere, typical void fraction, the typical drum outage (i.e. the unfilled distance from the top of the drum, in feet), and annual number of coke-cutting cycles.

(4) For each set of coking drums that are the same dimensions: The number of coking drums in the set, the height and diameter of the coke drums (in feet), the cumulative number of vessel openings for all delayed coking drums in the set, the typical venting pressure (in psig), void fraction (in cf gas/cf of vessel), and the mole fraction of methane in coking gas (in kg-mole CF_4/kg-mole gas, wet basis).

(5) The basis for the volumetric void fraction of the coke vessel prior to steaming and the basis for the mole fraction of methane in the coking gas.

(l) For process vents subject to § 98.253(j), the owner or operator shall report:

(1) The vent ID number (if applicable).

(2) The unit or operation associated with the emissions.

(3) The type of control device used to reduce methane (and other organic) emissions from the unit, if applicable.

(4) The calculated annual CO_2, CH_4, and N_2O emissions for each vent, expressed in metric tons of each pollutant emitted.

(5) The annual volumetric flow discharged to the atmosphere (in scf), mole fraction of each GHG above the concentration threshold, and for intermittent vents, the number of venting events and the cumulative venting time.

(m) For uncontrolled blowdown systems, the owner or operator shall report:

(1) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for uncontrolled blowdown systems.

(2) The total quantity (in Million bbl) of crude oil plus the quantity of intermediate products received from off-site that are processed at the facility in the reporting year.

(3) The methane emission factor used for uncontrolled blowdown systems and the basis for the value.

(n) For equipment leaks, the owner or operator shall report:

(1) The cumulative CH_4 emissions (in metric tons of each pollutant emitted) for all equipment leak sources.

(2) The method used to calculate the reported equipment leak emissions.

(3) The number of each type of emission source listed in Equation Y–21 of this subpart at the facility.

(o) For storage tanks, the owner or operator shall report:

(1) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for all storage tanks, except for those used to process unstabilized crude oil.

(2) The method used to calculate the reported storage tank emissions for storage tanks other than those processing unstabilized crude (AP–42, TANKS 4.09D, Equation Y–22 of this subpart, other).

(3) The total quantity (in MMbbl) of crude oil plus the quantity of intermediate products received from off-site that are processed at the facility in the reporting year.

(4) The cumulative CH_4 emissions (in metric tons of each pollutant emitted) for storage tanks used to process unstabilized crude oil.

(5) The method used to calculate the reported storage tank emissions for storage tanks processing unstabilized crude oil.

(6) The quantity of unstabilized crude oil received during the calendar year (in MMbbl), the average pressure differential (in psi), and the mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tank, and the basis for the mole fraction.

(7) The tank-specific methane composition data and the gas generation rate data, if you did not use Equation Y–23.

(p) For loading operations, the owner or operator shall report:

(1) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for loading operations.

(2) The quantity and types of materials loaded by vessel type (barge, tanker, marine vessel, etc.) that have an equilibrium vapor-phase concentration of methane of 0.5 volume percent or greater, and the type of vessels in which the material is loaded.

(3) The type of control system used to reduce emissions from the loading of material with an equilibrium vapor-phase concentration of methane of 0.5 volume percent or greater, if any (submerged loading, vapor balancing, etc.).

(q) Name of each method listed in § 98.254 or a description of manufacturer's recommended method used to determine a measured parameter.

§ 98.257 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records of all parameters monitored under § 98.255.

§ 98.258 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart Z—Phosphoric Acid Production

§ 98.260 Definition of the source category.

The phosphoric acid production source category consists of facilities with a wet-process phosphoric acid process line used to produce phosphoric acid. A wet-process phosphoric acid process line is the production unit or units identified by an individual identification number in an operating permit and/or any process unit or group of process units at a facility reacting phosphate rock from a common supply source with acid.

§ 98.261 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a phosphoric acid production process and the facility meets the requirements of either § 98.2(a)(1) or (a)(2).

§ 98.262 GHGs to report.

(a) You must report CO_2 process emissions from each wet-process phosphoric acid process line.

(b) You must report under subpart C of this part (General Stationary Fuel

Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary combustion unit following the requirements of subpart C of this part.

§ 98.263 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each wet-process phosphoric acid process line using the procedures in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the process CO_2 emissions by operating and maintaining a CEMS according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the process CO_2 emissions using the procedures in paragraphs (b)(1) and (b)(2) of this section.

(1) Calculate and report the process CO_2 emissions from each wet-process phosphoric acid process line using Equation Z–1 of this section:

$$E_m = \sum_{i=1}^{b}\sum_{n=1}^{z}\left(IC_{n,i} * P_{n,i}\right) * \frac{2000}{2205} * \frac{44}{12} \qquad \text{(Eq. Z-1)}$$

Where:

E_m = Annual CO_2 mass emissions from a wet-process phosphoric acid process line m (metric tons).

$IC_{n,i}$ = Inorganic carbon content of a grab sample batch of phosphate rock by origin i obtained during month n, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

$P_{n,i}$ = Mass of phosphate rock by origin i consumed in month n by wet-process phosphoric acid process line m (tons).

z = Number of months during which the process line m operates.

b = Number of different types of phosphate rock in month, by origin. If the grab sample is a composite sample of rock from more than one origin, b=1.

2000/2205 = Conversion factor to convert tons to metric tons.

44/12 = Ratio of molecular weights, CO_2 to carbon.

(2) You must determine the total emissions from the facility using Equation Z–2 of this section:

$$CO_2 = \sum_{m=1}^{p} E_m \qquad \text{(Eq. Z-2)}$$

Where:

CO_2 = Annual process CO_2 emissions from phosphoric acid production facility (metric tons/year).

E_m = Annual process CO_2 emissions from wet-process phosphoric acid process line m (metric tons/year).

p = Number of wet-process phosphoric acid process lines.

(c) If GHG emissions from a wet-process phosphoric acid process line are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

§ 98.264 Monitoring and QA/QC requirements.

(a) You must obtain a monthly grab sample of phosphate rock directly from the rock being fed to the process line. Conduct the representative bulk sampling using the applicable standard method in the Phosphate Mining States Methods Used and Adopted by the Association of Fertilizer and Phosphate Chemists AFPC Manual 10th Edition 2009—Version 1.9 (incorporated by reference, see § 98.7). If phosphate rock is obtained from more than one origin in a month, you must obtain a sample from each origin of rock or obtain a composite representative sample.

(b) You must determine the inorganic carbon content of each monthly grab sample of phosphate rock (consumed in the production of phosphoric acid) using the applicable standard method in the Phosphate Mining States Methods Used and Adopted by the Association of Fertilizer and Phosphate Chemists AFPC Manual 10th Edition 2009—Version 1.9 (incorporated by reference, *see* § 98.7).

(c) You must determine the mass of phosphate rock consumed each month (by origin) in each wet-process phosphoric acid process line. You can use existing plant procedures that are used for accounting purposes (such as sales records) or you can use data from existing monitoring equipment that is used to measure total mass flow of phosphorous-bearing feed under 40 CFR part 60 or part 63.

§ 98.265 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations in § 98.263(b) is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing value of the inorganic carbon content of phosphate rock (by origin), you must use the appropriate default factor provided in Table Z–1 of this subpart. Alternatively, the you must determine substitute data value by calculating the arithmetic average of the quality-assured values of inorganic carbon contents of phosphate rock of origin i (*see* Equation Z–1 of this subpart) from samples immediately preceding and immediately following the missing data incident. If no quality-assured data on inorganic carbon contents of phosphate rock of origin i are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for inorganic carbon contents for phosphate rock of origin i obtained after the missing data period.

(b) For each missing value of monthly mass consumption of phosphate rock (by origin), you must use the best available estimate based on all available process data or data used for accounting purposes.

§ 98.266 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) through (b) of this section.

(a) Annual phosphoric acid production by origin (as listed in Table Z–1 to this subpart) of the phosphate rock (tons).

(b) Annual phosphoric acid permitted production capacity (tons).

(c) Annual arithmetic average percent inorganic carbon in phosphate rock from monthly records.

(d) Annual phosphate rock consumption from monthly measurement records by origin, (as listed in Table Z–1 to this subpart) (tons).

(e) If you use a CEMS to measure CO_2 emissions, then you must report the information in paragraphs (e)(1) and (e)(2) of this section.

(1) The identification number of each wet-process phosphoric acid process line.

(2) The annual CO_2 emissions from each wet-process phosphoric acid process line (metric tons) and the relevant information required under 40 CFR 98.36 (e)(2)(vi) for the Tier 4 Calculation Methodology.

(f) If you do not use a CEMS to measure emissions, then you must report the information in paragraphs (f)(1) through (f)(8) of this section.

(1) Identification number of each wet-process phosphoric acid process line.

(2) Annual CO_2 emissions from each wet-process phosphoric acid process line (metric tons) as calculated by Equation Z–1 of this subpart.

(3) Annual phosphoric acid permitted production capacity (tons) for each wet-process phosphoric acid process line (metric tons).

(4) Method used to estimate any missing values of inorganic carbon content of phosphate rock for each wet-process phosphoric acid process line.

(5) Monthly inorganic carbon content of phosphate rock for each wet-process phosphoric acid process line (percent by weight, expressed as a decimal fraction).

(6) Monthly mass of phosphate rock consumed by origin, (as listed in Table Z–1 of this subpart) in production for each wet-process phosphoric acid process line (tons).

(7) Number of wet-process phosphoric acid process lines.

(8) Number of times missing data procedures were used to estimate phosphate rock consumption (months) and inorganic carbon contents of the phosphate rock (months).

§ 98.267 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) through (c) of this section for each wet-process phosphoric acid production facility.

(a) Monthly mass of phosphate rock consumed by origin (as listed in Table Z–1 of this subpart) (tons).

(b) Records of all phosphate rock purchases and/or deliveries (if vertically integrated with a mine).

(c) Documentation of the procedures used to ensure the accuracy of monthly phosphate rock consumption by origin, (as listed in Table Z–1 of this subpart).

§ 98.268 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE Z–1 TO SUBPART Z OF PART 98—DEFAULT CHEMICAL COMPOSITION OF PHOSPHATE ROCK BY ORIGIN

Origin	Total carbon (percent by weight)
Central Florida	1.6
North Florida	1.76
North Carolina (Calcined)	0.76
Idaho (Calcined)	0.60
Morocco	1.56

Subpart AA—Pulp and Paper Manufacturing

§ 98.270 Definition of source category.

(a) The pulp and paper manufacturing source category consists of facilities that produce market pulp (i.e., stand-alone pulp facilities), manufacture pulp and paper (i.e., integrated facilities), produce paper products from purchased pulp, produce secondary fiber from recycled paper, convert paper into paperboard products (e.g., containers), or operate coating and laminating processes.

(b) The emission units for which GHG emissions must be reported are listed in paragraphs (b)(1) through (b)(5) of this section:

(1) Chemical recovery furnaces at kraft and soda mills (including recovery furnaces that burn spent pulping liquor produced by both the kraft and semichemical process).

(2) Chemical recovery combustion units at sulfite facilities.

(3) Chemical recovery combustion units at stand-alone semichemical facilities.

(4) Pulp mill lime kilns at kraft and soda facilities.

(5) Systems for adding makeup chemicals ($CaCO_3$, Na_2CO_3) in the chemical recovery areas of chemical pulp mills.

§ 98.271 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a pulp and paper manufacturing process and the facility meets the requirements of either § 98.2(a)(1) or (a)(2).

§ 98.272 GHGs to report.

You must report the emissions listed in paragraphs (a) through (f) of this section:

(a) CO_2, biogenic CO_2, CH_4, and N_2O emissions from each kraft or soda chemical recovery furnace.

(b) CO_2, biogenic CO_2, CH_4, and N_2O emissions from each sulfite chemical recovery combustion unit.

(c) CO_2, biogenic CO_2, CH_4, and N_2O emissions from each stand-alone semichemical chemical recovery combustion unit.

(d) CO_2, biogenic CO_2, CH_4, and N_2O emissions from each kraft or soda pulp mill lime kiln.

(e) CO_2 emissions from addition of makeup chemicals ($CaCO_3$, Na_2CO_3) in the chemical recovery areas of chemical pulp mills.

(f) CO_2, CH_4, and N_2O combustion emissions from each stationary combustion unit. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§ 98.273 Calculating GHG emissions.

(a) For each chemical recovery furnace located at a kraft or soda facility, you must determine CO_2, biogenic CO_2, CH_4, and N_2O emissions using the procedures in paragraphs (a)(1) through (a)(3) of this section. CH_4 and N_2O emissions must be calculated as the sum of emissions from combustion of fossil fuels and combustion of biomass in spent liquor solids.

(1) Calculate fossil fuel-based CO_2 emissions from direct measurement of fossil fuels consumed and default emissions factors according to the Tier 1 methodology for stationary combustion sources in § 98.33(a)(1).

(2) Calculate fossil fuel-based CH_4 and N_2O emissions from direct measurement of fossil fuels consumed, default HHV, and default emissions factors and convert to metric tons of CO_2 equivalent according to the methodology for stationary combustion sources in § 98.33(c).

(3) Calculate biogenic CO_2 emissions and emissions of CH_4 and N_2O from biomass using measured quantities of spent liquor solids fired, site-specific HHV, and default or site-specific emissions factors, according to Equation AA–1 of this section:

$$CO_2, CH_4, or\ N_2O\ from\ biomass = (0.907.18) * Solids * HHV * EF \qquad \text{(Eq. AA-1)}$$

Where:

CO_2, CH_4, or N_2O, from Biomass = Biogenic CO_2 emissions or emissions of CH_4 or N_2O from spent liquor solids combustion (metric tons per year).
Solids = Mass of spent liquor solids combusted (short tons per year) determined according to § 98.274(b).
HHV = Annual high heat value of the spent liquor solids (mmBtu per kilogram) determined according to § 98.274(b).
EF = Default emission factor for CO_2, CH_4, or N_2O, from Table AA–1 of this subpart (kg CO_2, CH_4, or N_2O per mmBtu).
0.90718 = Conversion factor from short tons to metric tons.

(b) For each chemical recovery combustion unit located at a sulfite or stand-alone semichemical facility, you must determine CO_2, CH_4, and N_2O emissions using the procedures in paragraphs (b)(1) through (b)(4) of this section:

(1) Calculate fossil CO_2 emissions from fossil fuels from direct measurement of fossil fuels consumed and default emissions factors according to the Tier 1 Calculation Methodology for stationary combustion sources in § 98.33(a)(1).

(2) Calculate CH_4 and N_2O emissions from fossil fuels from direct measurement of fossil fuels consumed, default HHV, and default emissions factors and convert to metric tons of CO_2 equivalent according to the methodology for stationary combustion sources in § 98.33(c).

(3) Calculate biogenic CO_2 emissions using measured quantities of spent liquor solids fired and the carbon content of the spent liquor solids, according to Equation AA–2 of this section:

$$\text{Biogenic } CO_2 = \frac{44}{12} * \text{Solids} * \text{CC} * (0.90718) \qquad \text{(Eq. AA-2)}$$

Where:

Biogenic CO_2 = Annual CO_2 mass emissions for spent liquor solids combustion (metric tons per year).
Solids = Mass of the spent liquor solids combusted (short tons per year) determined according to § 98.274(b).
CC = Annual carbon content of the spent liquor solids, determined according to § 98.274(b) (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.90718 = Conversion from short tons to metric tons.

(4) Calculate CH_4 and N_2O emissions from biomass using Equation AA–1 of this section and the default CH_4 and N_2O emissions factors for kraft facilities in Table AA–1 of this subpart and convert the CH_4 or N_2O emissions to metric tons of CO_2 equivalent by multiplying each annual CH_4 and N_2O emissions total by the appropriate global warming potential (GWP) factor from Table A–1 of subpart A of this part.

(c) For each pulp mill lime kiln located at a kraft or soda facility, you must determine CO_2, CH_4, and N_2O emissions using the procedures in paragraphs (c)(1) through (c)(3) of this section:

(1) Calculate CO_2 emissions from fossil fuel from direct measurement of fossil fuels consumed and default HHV and default emissions factors, according to the Tier 1 Calculation Methodology for stationary combustion sources in § 98.33(a)(1); use the default HHV listed in Table C–1 of subpart C and the default CO_2 emissions factors listed in Table AA–2 of this subpart.

(2) Calculate CH_4 and N_2O emissions from fossil fuel from direct measurement of fossil fuels consumed, default HHV, and default emissions factors and convert to metric tons of CO_2 equivalent according to the methodology for stationary combustion sources in § 98.33(c); use the default HHV listed in Table C–1 of subpart C and the default CH_4 and N_2O emissions factors listed in Table AA–2 of this subpart.

(3) Biogenic CO_2 emissions from conversion of $CaCO_3$ to CaO are included in the biogenic CO_2 estimates calculated for the chemical recovery furnace in paragraph (a)(3) of this section.

(d) For makeup chemical use, you must calculate CO_2 emissions by using direct or indirect measurement of the quantity of chemicals added and ratios of the molecular weights of CO_2 and the makeup chemicals, according to Equation AA–3 of this section:

$$CO_2 = \left[M_{(CaCO_3)} * \frac{44}{100} + M_{(Na_2CO_3)} \frac{44}{105.99} \right] * 1000 \textit{ kg/metric ton} \qquad \text{(Eq. AA-3)}$$

Where:

CO_2 = CO_2 mass emissions from makeup chemicals (kilograms/yr).
M ($CaCO_3$) = Make-up quantity of $CaCO_3$ used for the reporting year (metric tons per year).
M ($NaCO_3$) = Make-up quantity of Na_2CO_3 used for the reporting year (metric tons per year).
44 = Molecular weight of CO_2.
100 = Molecular weight of $CaCO_3$.
105.99 = Molecular weight of Na_2CO_3.

§ 98.274 Monitoring and QA/QC requirements.

(a) Each facility subject to this subpart must quality assure the GHG emissions data according to the applicable requirements in § 98.34. All QA/QC data must be available for inspection upon request.

(b) Fuel properties needed to perform the calculations in Equations AA–1 and AA–2 of this subpart must be determined according to paragraphs (b)(1) through (b)(3) of this section.

(1) High heat values of black liquor must be determined no less than annually using T684 om–06 Gross Heating Value of Black Liquor, TAPPI (incorporated by reference, *see* § 98.7). If measurements are performed more frequently than annually, then the high heat value used in Equation AA–1 of this subpart must be based on the average of the representative measurements made during the year.

(2) The annual mass of spent liquor solids must be determined using either of the methods specified in paragraph (b)(2)(i) or (b)(2)(ii) of this section.

(i) Measure the mass of spent liquor solids annually (or more frequently) using T–650 om–05 Solids Content of Black Liquor, TAPPI (incorporated by reference in § 98.7). If measurements are performed more frequently than annually, then the mass of spent liquor solids used in Equation AA–1 of this subpart must be based on the average of the representative measurements made during the year.

(ii) Determine the annual mass of spent liquor solids based on records of measurements made with an online measurement system that determines the mass of spent liquor solids fired in a chemical recovery furnace or chemical recovery combustion unit.

(3) Carbon analyses for spent pulping liquor must be determined no less than annually using ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, *see* § 98.7). If measurements using ASTM D5373–08 are performed more frequently than annually, then the spent pulping liquor carbon content used in Equation AA–2 of this subpart must be based on the average of the representative measurements made during the year.

(c) Each facility must keep records that include a detailed explanation of how company records of measurements are used to estimate GHG emissions. The owner or operator must also document the procedures used to ensure the accuracy of the measurements of fuel, spent liquor solids, and makeup chemical usage, including, but not limited to calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must be recorded and the technical basis for these estimates must be provided. The procedures used to convert spent pulping liquor flow rates to units of mass (i.e., spent liquor solids firing rates) also must be documented.

(d) Records must be made available upon request for verification of the calculations and measurements.

§ 98.275 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the requirements of paragraphs (a) through (c) of this section:

(a) There are no missing data procedures for measurements of heat content and carbon content of spent pulping liquor. A re-test must be performed if the data from any annual measurements are determined to be invalid.

(b) For missing measurements of the mass of spent liquor solids or spent pulping liquor flow rates, use the lesser value of either the maximum mass or fuel flow rate for the combustion unit, or the maximum mass or flow rate that the fuel meter can measure.

(c) For the use of makeup chemicals (carbonates), the substitute data value shall be the best available estimate of makeup chemical consumption, based on available data (e.g., past accounting records, production rates). The owner or operator shall document and keep records of the procedures used for all such estimates.

§ 98.276 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information in paragraphs (a) through (k) of this section as applicable:

(a) Annual emissions of CO_2, biogenic CO_2, CH_4, biogenic CH_4 N_2O, and biogenic N_2O (metric tons per year).

(b) Annual quantities fossil fuels by type used in chemical recovery furnaces and chemical recovery combustion units in short tons for solid fuels, gallons for liquid fuels and scf for gaseous fuels.

(c) Annual mass of the spent liquor solids combusted (short tons per year), and basis for determining the annual mass of the spent liquor solids combusted (whether based on T650 om-05 Solids Content of Black Liquor, TAPPI (incorporated by reference, *see* § 98.7) or an online measurement system).

(d) The high heat value (HHV) of the spent liquor solids used in Equation AA–1 of this subpart (mmBtu per kilogram).

(e) The default emission factor for CO_2, CH_4, or N_2O, used in Equation AA–1 of this subpart (kg CO_2, CH_4, or N_2O per mmBtu).

(f) The carbon content (CC) of the spent liquor solids, used in Equation AA–2 of this subpart (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).

(g) Annual quantities of fossil fuels by type used in pulp mill lime kilns in short tons for solid fuels, gallons for liquid fuels and scf for gaseous fuels.

(h) Make-up quantity of $CaCO_3$ used for the reporting year (metric tons per year) used in Equation AA–3 of this subpart.

(i) Make-up quantity of Na_2CO_3 used for the reporting year (metric tons per year) used in Equation AA–3 of this subpart.

(j) Annual steam purchases (pounds of steam per year).

(k) Annual production of pulp and/or paper products produced (metric tons).

§ 98.277 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the records in paragraphs (a) through (f) of this section.

(a) GHG emission estimates (including separate estimates of biogenic CO_2) for each emissions source listed under § 98.270(b).

(b) Annual analyses of spent pulping liquor HHV for each chemical recovery furnace at kraft and soda facilities.

(c) Annual analyses of spent pulping liquor carbon content for each chemical recovery combustion unit at a sulfite or semichemical pulp facility.

(d) Annual quantity of spent liquor solids combusted in each chemical recovery furnace and chemical recovery combustion unit, and the basis for detemining the annual quantity of the spent liquor solids combusted (whether based on T650 om–05 Solids Content of Black Liquor, TAPPI (incorporated by reference, *see* § 98.7) or an online measurement system). If an online measurement system is used, you must retain records of the calculations used to determine the annual quantity of spent liquor solids combusted from the continuous measurements.

(e) Annual steam purchases.

(f) Annual quantities of makeup chemicals used.

§ 98.278 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE AA–1 TO SUBPART AA OF PART 98—KRAFT PULPING LIQUOR EMISSIONS FACTORS FOR BIOMASS-BASED CO_2, CH_4, AND N_2O

Wood furnish	Biomass-based emissions factors (kg/mmBtu HHV)		
	CO_2[a]	CH_4	N_2O
North American Softwood	94.4	0.030	0.005
North American Hardwood	93.7		
Bagasse	95.5		
Bamboo	93.7		

TABLE AA–1 TO SUBPART AA OF PART 98—KRAFT PULPING LIQUOR EMISSIONS FACTORS FOR BIOMASS-BASED CO_2, CH_4, AND N_2O—Continued

Wood furnish	Biomass-based emissions factors (kg/mmBtu HHV)		
	CO_2 [a]	CH_4	N_2O
Straw	95.1		

[a] Includes emissions from both the recovery furnace and pulp mill lime kiln.

TABLE AA–2 TO SUBPART AA OF PART 98—KRAFT LIME KILN AND CALCINER EMISSIONS FACTORS FOR FOSSIL FUEL-BASED CO_2, CH_4, AND N_2O

Fuel	Fossil fuel-based emissions factors (kg/mmBtu HHV)					
	Kraft lime kilns			Kraft calciners		
	CO_2	CH_4	N_2O	CO_2	CH_4	N_2O
Residual Oil	76.7	0.0027	0	76.7	0.0027	0.0003
Distillate Oil	73.5			73.5		0.0004
Natural Gas	56.0			56.0		0.0001
Biogas	0					0.0001

Subpart BB—Silicon Carbide Production

§ 98.280 Definition of the source category.

Silicon carbide production includes any process that produces silicon carbide for abrasive purposes.

§ 98.281 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a silicon carbide production process and the facility meets the requirements of either § 98.2(a)(1) or (a)(2).

§ 98.282 GHGs to report.

You must report:

(a) CO_2 and CH_4 process emissions from all silicon carbide process units or furnaces combined.

(b) CO_2, CH_4, and N_2O emissions from each stationary combustion unit. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§ 98.283 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each silicon carbide process unit or production furnace using the procedures in either paragraph (a) or (b) of this section. You must determine CH_4 process emissions in accordance with the procedures specified in paragraph (d) of this section.

(a) Calculate and report under this subpart the process CO_2 emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the process CO_2 emissions using the procedures in paragraphs (b)(1) and (b)(2) of this section.

(1) Use Equation BB–1 of this section to calculate the facility-specific emissions factor for determining CO_2 emissions. The carbon content must be measured monthly and used to calculate a monthly CO_2 emisssions factor:

$$EF_{CO2,n} = 0.65 * CCF_n * \left(\frac{44}{12}\right) \qquad \text{(Eq. BB-1)}$$

Where:

$EF_{CO2,n}$ = CO_2 emissions factor in month n (metric tons CO_2/metric ton of petroleum coke consumed).

0.65 = Adjustment factor for the amount of carbon in silicon carbide product (assuming 35 percent of carbon input is in the carbide product).

CCF_n = Carbon content factor for petroleum coke consumed in month n from the supplier or as measured by the applicable method incorporated by reference in § 98.7 according to § 98.284(c) (percent by weight expressed as a decimal fraction).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(2) Use Equation BB–2 of this section to calculate annual CO_2 process emissions from all silicone carbide production:

$$CO_2 = \sum_{n=1}^{12}\left[T_n * EF_{CO2,n}\right] * \frac{2000}{2205} \qquad \text{(Eq. BB-2)}$$

Where:

CO_2 = Annual CO_2 emissions from silicon carbide production facility (metric tons CO_2).

T_n = Petroleum coke consumption in month n (tons).

$EF_{CO2,n}$ = CO_2 emissions factor from month n (calculated in Equation BB–1 of this section).
2000/2205 = Conversion factor to convert tons to metric tons.
n = Number of month.

(c) If GHG emissions from a silicon carbide production furnace or process unit are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

(d) You must calculate annual process CH_4 emissions from all silicon carbide production combined using Equation BB–3 of this section:

$$CH_4 = \sum_{n=1}^{12}\left[T_n * 10.2\right] * \frac{2000}{2205} * 0.001 \qquad \text{(Eq. BB-3)}$$

Where:
CH_4 = Annual CH_4 emissions from silicon carbide production facility (metric tons CH_4).
T_n = Petroleum coke consumption in month n (tons).
10.2 = CH_4 emissions factor (kg CH_4/metric ton coke).
2000/2205 = Conversion factor to convert tons to metric tons.
0.001 = Conversion factor from kilograms to metric tons.
n = Number of month.

§ 98.284 Monitoring and QA/QC requirements.

(a) You must measure your consumption of petroleum coke using plant instruments used for accounting purposes including direct measurement weighing the petroleum coke fed into your process (by belt scales or a similar device) or through the use of purchase records.

(b) You must document the procedures used to ensure the accuracy of monthly petroleum coke consumption measurements.

(c) For CO_2 process emissions, you must determine the monthly carbon content of the petroleum coke using reports from the supplier. Alternatively, facilities can measure monthly carbon contents of the petroleum coke using ASTM D3176–89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, *see* § 98.7) and ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, *see* § 98.7).

(d) For quality assurance and quality control of the supplier data, you must conduct an annual measurement of the carbon content of the petroleum coke using ASTM D3176–89 and ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, *see* § 98.7).

§ 98.285 Procedures for estimating missing data.

For the petroleum coke input procedure in § 98.283(b), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing value of the monthly carbon content of petroleum coke, the substitute data value shall be the arithmetic average of the quality-assured values of carbon contents immediately preceding and immediately following the missing data incident. If no quality-assured data on carbon contents are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon contents obtained after the missing data period.

(b) For each missing value of the monthly petroleum coke consumption, the substitute data value shall be the best available estimate of the petroleum coke consumption based on all available process data or information used for accounting purposes (such as purchase records).

§ 98.286 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable for each silicon carbide production facility.

(a) If a CEMS is used to measure process CO_2 emissions, you must report under this subpart the relevant information required for the Tier 4 Calculation Methodology in § 98.36 and the information listed in this paragraph (a):

(1) Annual consumption of petroleum coke (tons).

(2) Annual production of silicon carbide (tons).

(3) Annual production capacity of silicon carbide (tons).

(b) If a CEMS is not used to measure process CO_2 emissions, you must report the information listed in this paragraph (b) for all furnaces combined:

(1) Monthly consumption of petroleum coke (tons).

(2) *Annual production of* silicon carbide (tons).

(3) Annual production capacity of silicon carbide (tons).

(4) Carbon content factor of petroleum coke from the supplier or as measured by the applicable method in § 98.284(c) for each month (percent by weight expressed as a decimal fraction).

(5) Whether carbon content of the petroleum coke is based on reports from the supplier or through self measurement using applicable ASTM standard method.

(6) CO_2 emissions factor calculated for each month (metric tons CO_2/metric ton of petroleum coke consumed).

(7) Sampling analysis results for carbon content of consumed petroleum coke as determined for QA/QC of supplier data under § 98.284(d) (percent by weight expressed as a decimal fraction).

(8) Number of times in the reporting year that missing data procedures were followed to measure the carbon contents of petroleum coke (number of months) and petroleum coke consumption (number of months).

§ 98.287 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) and (b) of this section for each silicon carbide production facility.

(a) If a CEMS is used to measure CO_2 emissions, you must retain under this subpart the records required for the Tier 4 Calculation Methodology in § 98.37

and the information listed in this paragraph (a):

(1) Records of all petroleum coke purchases.

(2) Annual operating hours.

(b) If a CEMS is not used to measure emissions, you must retain records for the information listed in this paragraph (b):

(1) Records of all analyses and calculations conducted for reported data listed in § 98.286(b).

(2) Records of all petroleum coke purchases.

(3) Annual operating hours.

§ 98.288 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart CC—Soda Ash Manufacturing

§ 98.290 Definition of the source category.

(a) A soda ash manufacturing facility is any facility with a manufacturing line that produces soda ash by one of the methods in paragraphs (a)(1) through (3) of this section:

(1) Calcining trona.

(2) Calcining sodium sesquicarbonate.

(3) Using a liquid alkaline feedstock process that directly produces CO_2.

(b) In the context of the soda ash manufacturing sector, ''calcining'' means the thermal/chemical conversion of the bicarbonate fraction of the feedstock to sodium carbonate.

§ 98.291 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a soda ash manufacturing process and the facility meets the requirements of either § 98.2(a)(1) or (a)(2).

§ 98.292 GHGs to report.

You must report:

(a) CO_2 process emissions from each soda ash manufacturing line combined.

(b) CO_2 combustion emissions from each soda ash manufacturing line.

(c) CH_4 and N_2O combustion emissions from each soda ash manufacturing line. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) CO_2, CH_4, and N_2O emissions from each stationary combustion unit other than soda ash manufacturing lines. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§ 98.293 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each soda ash manufacturing line using the procedures specified in paragraph (a) or (b) of this section.

(a) For each soda ash manufacturing line that meets the conditions specified in § 98.33(b)(4)(ii) or (b)(4)(iii), you must calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For each soda ash manufacturing line that is not subject to the requirements in paragraph (a) of this section, calculate and report the process CO_2 emissions from the soda ash manufacturing line by using the procedure in either paragraphs (b)(1), (b)(2), or (b)(3) of this section; and the combustion CO_2 emissions using the procedure in paragraph (b)(4) of this section.

(1) Calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(2) Use either Equation CC–1 or Equation CC–2 of this section to calculate annual CO_2 process emissions from each manufacturing line that calcines trona to produce soda ash:

$$E_k = \sum_{n=1}^{12} \left[\left(IC_T\right)_n * \left(T_t\right)_n \right] * \frac{2000}{2205} * \frac{0.097}{1} \qquad \text{(Eq. CC-1)}$$

$$E_k = \sum_{n=1}^{12} \left[\left(IC_{sa}\right)_n * \left(T_{sa}\right)_n \right] * \frac{2000}{2205} * \frac{0.138}{1} \qquad \text{(Eq. CC-2)}$$

Where:

E_k = Annual CO_2 process emissions from each manufacturing line, k (metric tons).

$(IC_T)_n$ = Inorganic carbon content (percent by weight, expressed as a decimal fraction) in trona input, from the carbon analysis results for month n. This represents the ratio of trona to trona ore.

$(IC_{sa})_n$ = Inorganic carbon content (percent by weight, expressed as a decimal fraction) in soda ash output, from the carbon analysis results for month n. This represents the purity of the soda ash produced.

$(T_t)_n$ = Mass of trona input in month n (tons).

$(T_{sa})_n$ = Mass of soda ash output in month n (tons).

2000/2205 = Conversion factor to convert tons to metric tons.

0.097/1 = Ratio of ton of CO_2 emitted for each ton of trona.

0.138/1 = Ratio of ton of CO_2 emitted for each ton of soda ash produced.

(3) *Site-specific emission factor method.* Use Equations CC–3, CC–4, and CC–5 of this section to determine annual CO_2 process emissions from manufacturing lines that use the liquid alkaline feedstock process to produce soda ash. You must conduct an annual performance test and measure CO_2 emissions and flow rates at all process vents from the mine water stripper/evaporator for each manufacturing line and calculate CO_2 emissions as described in paragraphs (b)(3)(i) through (b)(3)(iv) of this section.

(i) During the performance test, you must measure the process vent flow from each process vent during the test and calculate the average rate for the test period in metric tons per hour.

(ii) Using the test data, you must calculate the hourly CO_2 emission rate using Equation CC–3 of this section:

$$ER_{CO2} = \left[(C_{co2} * 10000) * 2.59x10^{-9} * 44 \right] * (Q * 60) * 4.53x10^{-4} \qquad \text{(Eq. CC-3)}$$

Where:

ER_{CO2} = CO_2 mass emission rate (metric tons/hour).

C_{CO2} = Hourly CO_2 concentration (percent CO_2) as determined by § 98.294(c).

10000 = Parts per million per percent

2.59×10^{-9} = Conversion factor (pounds-mole/dscf/ppm).

44 = Pounds per pound-mole of carbon dioxide.

Q = Stack gas volumetric flow rate per minute (dscfm).

60 = Minutes per hour

4.53×10^{-4} = Conversion factor (metric tons/pound)

(iii) Using the test data, you must calculate a CO_2 emission factor for the process using Equation CC–4 of this section:

$$EF_{CO2} = \frac{ER_{CO2}}{\left(V_t * 4.53x10^{-4}\right)} \qquad \text{(Eq. CC-4)}$$

Where:

EF_{CO2} = CO_2 emission factor (metric tons CO_2/metric ton of process vent flow from mine water stripper/evaporator).

ER_{CO2} = CO_2 mass emission rate (metric tons/hour).

V_t = Process vent flow rate from mine water stripper/evaporator during annual performance test (pounds/hour).

4.53×10^{-4} = Conversion factor (metric tons/pound)

(iv) You must calculate annual CO_2 process emissions from each manufacturing line using Equation CC–5 of this section:

$$E_k = EF_{CO2} * \left(V_a * 0.453\right) * H \qquad \text{(Eq. CC-5)}$$

Where:

E_k = Annual CO_2 process emissions for each manufacturing line, k (metric tons).

EF_{CO2} = CO_2 emission factor (metric tons CO_2/metric ton of process vent flow from mine water stripper/evaporator).

V_a = Annual process vent flow rate from mine water stripper/evaporator (thousand pounds/hour).

H = Annual operating hours for the each manufacturing line.

0.453 = Conversion factor (metric tons/thousand pounds).

(4) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion CO_2, CH_4, and N_2O emissions in the soda ash manufacturing line according to the applicable requirements in subpart C.

§ 98.294 Monitoring and QA/QC requirements.

Section 98.293 provides three different procedures for emission calculations. The appropriate paragraphs (a) through (c) of this section should be used for the procedure chosen.

(a) If you determine your emissions using § 98.293(b)(2) (Equation CC–1 of this subpart) you must:

(1) Determine the monthly inorganic carbon content of the trona from a weekly composite analysis for each soda ash manufacturing line, using a modified version of ASTM E359–00 (Reapproved 2005)e1, Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate) (incorporated by reference, see § 98.7). ASTM E359–00(Reapproved 2005) e1 is designed to measure the total alkalinity in soda ash not in trona. The modified method of ASTM E359–00 adjusts the regular ASTM method to express the results in terms of trona. Although ASTM E359–00 (Reapproved 2005) e1 uses manual titration, suitable autotitrators may also be used for this determination.

(2) Measure the mass of trona input produced by each soda ash manufacturing line on a monthly basis using belt scales or methods used for accounting purposes.

(3) Document the procedures used to ensure the accuracy of the monthly measurements of trona consumed.

(b) If you calculate CO_2 process emissions based on soda ash production (§ 98.293(b)(2) Equation CC–2 of this subpart), you must:

(1) Determine the inorganic carbon content of the soda ash (i.e., soda ash purity) using ASTM E359–00 (Reapproved 2005) e1 Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate) (incorporated by reference, see § 98.7). Although ASTM E359–00 (Reapproved 2005) e1 uses manual titration, suitable autotitrators may also be used for this determination.

(2) Measure the mass of soda ash produced by each soda ash manufacturing line on a monthly basis using belt scales, by weighing the soda ash at the truck or rail loadout points of your facility, or methods used for accounting purposes.

(3) Document the procedures used to ensure the accuracy of the monthly measurements of soda ash produced.

(c) If you calculate CO_2 emissions using the site-specific emission factor method in § 98.293(b)(3), you must:

(1) Conduct an annual performance test that is based on representative performance (i.e., performance based on normal operating conditions) of the affected process.

(2) Sample the stack gas and conduct three emissions test runs of 1 hour each.

(3) Conduct the stack test using EPA Method 3A at 40 CFR part 60, appendix A–2 to measure the CO_2 concentration, Method 2, 2A, 2C, 2D, or 2F at 40 CFR part 60, appendix A–1 or Method 26 at 40 CFR part 60, appendix A–2 to determine the stack gas volumetric flow rate. All QA/QC procedures specified in the reference test methods and any associated performance specifications apply. For each test, the facility must prepare an emission factor determination report that must include the items in paragraphs (c)(3)(i) through (c)(3)(iii) of this section.

(i) Analysis of samples, determination of emissions, and raw data.

(ii) All information and data used to derive the emissions factor(s).

(iii) You must determine the average process vent flow rate from the mine water stripper/evaporater during each test and document how it was determined.

(4) You must also determine the annual vent flow rate from the mine water stripper/evaporater from monthly information using the same plant instruments or procedures used for accounting purposes (i.e., volumetric flow meter).

§ 98.295 Procedures for estimating missing data.

For the emission calculation methodologies in § 98.293(b)(2) and (b)(3), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., inorganic carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) through (d) of this section. You must document and keep records of the procedures used for all such missing value estimates.

(a) For each missing value of the weekly composite of inorganic carbon content of either soda ash or trona, the substitute data value shall be the arithmetic average of the quality-assured values of inorganic carbon contents from the week immediately preceding and the week immediately following the missing data incident. If no quality-assured data on inorganic carbon contents are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon contents obtained after the missing data period.

(b) For each missing value of either the monthly soda ash production or the trona consumption, the substitute data value shall be the best available estimate(s) of the parameter(s), based on all available process data or data used for accounting purposes.

(c) For each missing value collected during the performance test (hourly CO_2 concentration, stack gas volumetric flow rate, or average process vent flow from mine water stripper/evaporator during performance test), you must repeat the annual performance test following the calculation and monitoring and QA/QC requirements under §§ 98.293(b)(3) and 98.294(c).

(d) For each missing value of the monthly process vent flow rate from mine water stripper/evaporator, the subsititute data value shall be the best available estimate(s) of the parameter(s), based on all available process data or the lesser of the maximum capacity of the system or the maximum rate the meter can measure.

§ 98.296 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as appropriate for each soda ash manufacturing facility.

(a) If a CEMS is used to measure CO_2 emissions, then you must report under this subpart the relevant information required under § 98.36 and the following information in this paragraph (a):

(1) Annual consumption of trona or liquid alkaline feedstock for each manufacturing line (metric tons).

(2) Annual production of soda ash for each manufacturing line (tons).

(3) Annual production capacity of soda ash for each manufacturing line (tons).

(4) Identification number of each manufacturing line.

(b) If a CEMS is not used to measure CO_2 emissions, then you must report the information listed in this paragraph (b):

(1) Identification number of each manufacturing line.

(2) Annual process CO_2 emissions from each soda ash manufacturing line (metric tons).

(3) Annual production of soda ash (tons).

(4) Annual production capacity of soda ash for each manufacturing line (tons).

(5) Monthly consumption of trona or liquid alkaline feedstock for each manufacturing line (tons).

(6) Monthly production of soda ash for each manufacturing line (metric tons).

(7) Inorganic carbon content factor of trona or soda ash (depending on use of Equations CC–1 or CC–2 of this subpart) as measured by the applicable method in § 98.294(b) or (c) for each month (percent by weight expressed as a decimal fraction).

(8) Whether CO_2 emissions for each manufacturing line were calculated using a trona input method as described in Equation CC–1 of this subpart, a soda ash output method as described in Equation CC–2 of this subpart, or a site-specific emission factor method as described in Equations CC–3 through CC–5 of this subpart.

(9) Number of manufacturing lines located used to produce soda ash.

(10) If you produce soda ash using the liquid alkaline feedstock process and use the site-specific emission factor method (§ 98.293(b)(3)) to estimate emissions then you must report the following relevant information:

(i) Stack gas volumetric flow rate per minute (dscfm)

(ii) Hourly CO_2 concentration (percent CO_2)

(iii) CO_2 emission factor (metric tons CO_2/metric tons of process vent flow from mine water stripper/evaporator).

(iv) CO_2 mass emission rate (metric tons/hour).

(v) Average process vent flow from mine water stripper/evaporater during performance test (pounds/hour).

(vi) Annual process vent flow rate from mine stripper/evaporator (thousand pounds/hour).

(vii) Annual operating hours for each manufacturing line used to produce soda ash using liquid alkaline feedstock (hours).

(11) Number of times missing data procedures were used and for which parameter as specified in this paragraph (b)(11):

(i) Trona or soda ash (number of months).

(ii) Inorganic carbon contents of trona or soda ash (weeks).

(iii) Process vent flow rate from mine water stripper/evaporator (number of months).

(iv) Stack gas volumetric flow rate during performance test (number of times).

(v) Hourly CO_2 concentration (number of times).

(vi) Average vent process vent flow rate from mine stripper/evaporator during performance test (number of times).

§ 98.297 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) and (b) of this section for each soda ash manufacturing line.

(a) If a CEMS is used to measure CO_2 emissions, then you must retain under this subpart the records required for the Tier 4 Calculation Methodology specified in subpart C of this part and the information listed in this paragraph (a):

(1) Monthly production of soda ash (tons)

(2) Monthly consumption of trona or liquid alkaline feedstock (tons)

(3) Annual operating hours (hours).

(b) If a CEMS is not used to measure emissions, then you must retain records for the information listed in this paragraph (b):

(1) Records of all analyses and calculations conducted for determining all reported data as listed in § 98.296(b).

(2) If using Equation CC–1 or CC–2 of this subpart, weekly inorganic carbon content factor of trona or soda ash, depending on method chosen, as measured by the applicable method in § 98.294(b) (percent by weight expressed as a decimal fraction).

(3) Annual operating hours for each manufacturing line used to produce soda ash (hours).

(4) You must document the procedures used to ensure the accuracy of the monthly trona consumption or soda ash production measurements including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

(5) If you produce soda ash using the liquid alkaline feedstock process and use the site-specific emission factor method to estimate emissions (§ 98.293(b)(3)) then you must also retain the following relevant information:

(i) Records of performance test results.

(ii) You must document the procedures used to ensure the accuracy of the annual average vent flow measurements including, but not limited to, calibration of flow rate meters and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§ 98.298 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart DD—[Reserved]

Subpart EE—Titanium Dioxide Production

§ 98.310 Definition of the source category.

The titanium dioxide production source category consists of facilities that use the chloride process to produce titanium dioxide.

§ 98.311 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a titanium dioxide production process and the facility meets the requirements of either § 98.2(a)(1) or (a)(2).

§ 98.312 GHGs to report.

(a) You must report CO_2 process emissions from each chloride process line as required in this subpart.

(b) You must report CO_2, CH_4, and N_2O emissions from each stationary combustion unit under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§ 98.313 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions for each chloride process line using the procedures in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the process CO_2 emissions by operating and maintaining a CEMS according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the annual process CO_2 emissions for each chloride process line by determining the mass of calcined petroleum coke consumed in each line as specified in paragraphs (b)(1) through (b)(3) of this section. Use Equation EE–1 of this section to calulate annual combined process CO_2 emissions from all process lines and use Equation EE–2 of this section to calculate annual process CO_2 emissions for each process line. If your facility generates carbon-containing waste, use Equation EE–3 of this section to estimate the annual quantity of carbon-containing waste generated and its carbon contents according to § 98.314(e) and (f):

(1) You must calculate the annual CO_2 process emissions from all process lines at the facility using Equation EE–1 of this section:

$$CO_2 = \sum_{p=1}^{m} E_p \qquad \text{(Eq. EE-1)}$$

Where:

CO_2 = Annual CO_2 emissions from titanium dioxide production facility (metric tons/year).

E_p = Annual CO_2 emissions from chloride process line p (metric tons), determined using Equation EE–2 of this section.

p = Process line.

m = Number of separate chloride process lines located at the facility.

(2) You must calculate the annual CO_2 process emissions from each process lines at the facility using Equation EE–2 of this section:

$$E_p = \sum_{n=1}^{12} \frac{44}{12} * C_{p,n} * \frac{2000}{2205} * CCF_n \qquad \text{(Eq. EE-2)}$$

Where:

E_p = Annual CO_2 mass emissions from chloride process line p (metric tons).

$C_{p,n}$ = Calcined petroleum coke consumption for process line p in month n (tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

2000/2205 = Conversion of tons to metric tons.

CCF_n = Carbon content factor for petroleum coke consumed in month n from the supplier or as measured by the applicable method incorporated by reference in § 98.7 according to § 98.314(c) (percent by weight expressed as a decimal fraction).

n = Number of month.

(3) If facility generates carbon-containing waste, you must calculate the total annual quantity of carbon-containing waste produced from all process lines using Equation EE–3 of this section and its carbon contents according to § 98.314(e) and (f):

$$TWC = \sum_{p=1}^{m} \sum_{n=1}^{12} WC_{p,n} \qquad \text{(Eq. EE-3)}$$

Where:

TWC = Annual production of carbon-containing waste from titanium dioxide production facility (tons).

$WC_{p,n}$ = Production of carbon-containing waste in month n from chloride process line p (tons).

p = Process line.

m = Total number of process lines.

n = Number of month.

(c) If GHG emissions from a chloride process line are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process CO_2 emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

§ 98.314 Monitoring and QA/QC requirements.

(a) You must measure your consumption of calcined petroleum coke using plant instruments used for accounting purposes including direct measurement weighing the petroleum coke fed into your process (by belt scales or a similar device) or through the use of purchase records.

(b) You must document the procedures used to ensure the accuracy of monthly calcined petroleum coke consumption measurements.

(c) You must determine the carbon content of the calcined petroleum coke each month based on reports from the supplier. Alternatively, facilities can measure monthly carbon contents of the petroleum coke using ASTM D3176–89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, *see* § 98.7) and ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, *see* § 98.7).

(d) For quality assurance and quality control of the supplier data, you must conduct an annual measurement of the carbon content from a representative sample of the petroleum coke consumed using ASTM D3176–89 and ASTM D5373–08.

(e) You must determine the quantity of carbon-containing waste generated from the each titanium production line dioxide using plant instruments used for accounting purposes including direct measurement weighing the carbon-containing waste not used during the process (by belt scales or a similar device) or through the use of sales records.

(f) You must determine the carbon contents of the carbon-containing waste from each titanium production line on an annual basis by collecting and analyzing a representative sample of the material using ASTM D3176–89 and ASTM D5373–08.

§ 98.315 Procedures for estimating missing data.

For the petroleum coke input procedure in § 98.313(b), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., carbon content values, etc.). Therefore, whenever the monitoring and quality assurance procedures in § 98.315 cannot be followed, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) through (c) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing value of the monthly carbon content of calcined petroleum coke the substitute data value shall be the arithmetic average of the quality-assured values of carbon contents for the month immediately preceding and the month immediately following the missing data incident. If no quality-assured data on carbon contents are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon contents obtained after the missing data period.

(b) For each missing value of the monthly calcined petroleum coke consumption and/or carbon-containing waste, the substitute data value shall be the best available estimate of the monthly petroleum coke consumption based on all available process data or information used for accounting purposes (such as purchase records).

(c) For each missing value of the carbon content of carbon-containing waste, you must conduct a new analysis following the procedures in § 98.314(f).

§ 98.316 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable for each titanium dioxide production line.

(a) If a CEMS is used to measure CO_2 emissions, then you must report the relevant information required under § 98.36(e)(2)(vi) for the Tier 4 Calculation Methodology and the following information in this paragraph (a).

(1) Identification number of each process line.

(2) Annual consumption of calcined petroleum coke (tons).

(3) Annual production of titanium dioxide (tons).

(4) Annual production capacity of titanium dioxide (tons).

(5) Annual production of carbon-containing waste (tons), if applicable.

(b) If a CEMS is not used to measure CO_2 emissions, then you must report the information listed in this paragraph (b):

(1) Identification number of each process line.

(2) Annual CO_2 emissions from each chloride process line (metric tons/year).

(3) Annual consumption of calcined petroleum coke for each process line (tons).

(4) Annual production of titanium dioxide for each process line (tons).

(5) Annual production capacity of titanium dioxide for each process line (tons).

(6) Calcined petroleum coke consumption for each process line for each month (tons).

(7) Annual production of carbon-containing waste for each process line (tons), if applicable.

(8) Monthly production of titanium dioxide for each process line (tons).

(9) Monthly carbon content factor of petroleum coke from the supplier (percent by weight expressed as a decimal fraction).

(10) Whether monthly carbon content of the petroleum coke is based on reports from the supplier or through self measurement using applicable ASTM standard methods.

(11) Carbon content for carbon-containing waste (percent by weight expressed as a decimal fraction).

(12) If carbon content of petroleum coke is based on self measurement, the ASTM standard methods used.

(13) Sampling analysis results of carbon content of petroleum coke as determined for QA/QC of supplier data under § 98.314(d) (percent by weight expressed as a decimal fraction).

(14) Number of separate chloride process lines located at the facility.

(15) The number of times in the reporting year that missing data procedures were followed to measure the carbon contents of petroleum coke (number of months); petroleum coke consumption (number of months); carbon-containing waste generated (number of months); and carbon contents of the carbon-containing waste (number of times during year).

§ 98.317 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) and (b) of this section for each titanium dioxide production facility.

(a) If a CEMS is used to measure CO_2 emissions, then you must retain under this subpart required for the Tier 4 Calculation Methodology in § 98.37 and the information listed in this paragraph (a):

(1) Records of all calcined petroleum coke purchases.

(2) Annual operating hours for each titanium dioxide process line.

(b) If a CEMS is not used to measure CO_2 emissions, then you must retain records for the information listed in this paraghraph:

(1) Records of all calcined petroleum coke purchases (tons).

(2) Records of all analyses and calculations conducted for all reported data as listed in § 98.316(b).

(3) Sampling analysis results for carbon content of consumed calcined petroleum coke (percent by weight expressed as a decimal fraction).

(4) Sampling analysis results for the carbon content of carbon containing waste (percent by weight expressed as a decimal fraction), if applicable.

(5) Monthly production of carbon-containing waste (tons).

(6) You must document the procedures used to ensure the accuracy of the monthly petroleum coke consumption and quantity of carbon-containing waste measurement including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

(7) Annual operating hours for each titanium dioxide process line (hours).

§ 98.318 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart FF—[Reserved]

Subpart GG—Zinc Production

§ 98.330 Definition of the source category.

The zinc production source category consists of zinc smelters and secondary zinc recycling facilities.

§ 98.331 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a zinc production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.332 GHGs to report.

You must report:

(a) CO_2 process emissions from each Waelz kiln and electrothermic furnace used for zinc production.

(b) CO_2, CH_4, and N_2O combustion emissions from each Waelz kiln. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(c) CO_2, CH_4, and N_2O emissions from each stationary combustion unit other than Waelz kilns. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§ 98.333 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions using the procedures specified in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the process or combined process and combustion CO_2 emissions by operating and maintaining a CEMS according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the process CO_2 emissions by following paragraphs (b)(1) and (b)(2) of this section.

(1) For each Waelz kiln or electrothermic furnace at your facility used for zinc production, you must determine the mass of carbon in each carbon-containing material, other than fuel, that is fed, charged, or otherwise introduced into each Waelz kiln and electrothermic furnace at your facility for each year and calculate annual CO_2 process emissions from each affected unit at your facility using Equation GG–1 of this section. For electrothermic furnaces, carbon containing input materials include carbon eletrodes and carbonaceous reducing agents. For Waelz kilns, carbon containing input materials include carbonaceous reducing agents. If you document that a specific material contributes less than 1 percent of the total carbon into the process, you do not have to include the material in your calculation using Equation R–1 of § 98.183.

$$E_{CO2k} = \frac{44}{12} * \frac{2000}{2205} * \left[(Zinc)_k * (C_{Zinc})_k + (Flux)_k * (C_{Flux})_k + (Electrode)_k * (C_{Electrode})_k + (Carbon)_k * (C_{carbon})_k \right] \quad \text{(Eq. GG-1)}$$

Where:

E_{CO2k} = Annual CO_2 process emissions from individual Waelz kiln or electrothermic furnace ''k'' (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

2000/2205 = Conversion factor to convert tons to metric tons.

$(Zinc)_k$ = Annual mass of zinc bearing material charged to kiln or furnace ''k'' (tons).

$(C_{Zinc})_k$ = Carbon content of the zinc bearing material, from the annual carbon analysis for kiln or furnace ''k'' (percent by weight, expressed as a decimal fraction).

$(Flux)_k$ = Annual mass of flux materials (e.g., limestone, dolomite) charged to kiln or furnace ''k'' (tons).

$(C_{Flux})_k$ = Carbon content of the flux materials charged to kiln or furnace ''k'', from the annual carbon analysis (percent by weight, expressed as a decimal fraction).

$(Electrode)_k$ = Annual mass of carbon electrode consumed in kiln or furnace ''k'' (tons).

$(C_{Electrode})_k$ = Carbon content of the carbon electrode consumed in kiln or furnace ''k'', from the annual carbon analysis (percent by weight, expressed as a decimal fraction).

$(Carbon)_k$ = Annual mass of carbonaceous materials (e.g., coal, coke) charged to the kiln or furnace ''k''(tons).

$(C_{Carbon})_k$ Carbon content of the carbonaceous materials charged to kiln or furnace, ''k'', from the annual carbon analysis (percent by weight, expressed as a decimal fraction).

(2) You must determine the CO_2 emissions from all of the Waelz kilns or electrothermic furnaces at your facility using Equation GG–2 of this section.

$$CO_2 = \sum_{k=1}^{n} E_{CO2_k} \quad \text{(Eq. GG-2)}$$

Where:

CO_2 = Annual combined CO_2 emissions from all Waelz kilns or electrothermic furnaces (tons).

E_{CO2_k} = Annual CO_2 emissions from each Waelz kiln or electrothermic furnace k calculated using Equation GG–1 of this section (tons).

n = Total number of Waelz kilns or electrothermic furnaces at facility used for the zinc production.

(c) If GHG emissions from a Waelz kiln or electrothermic furnace are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

§ 98.334 Monitoring and QA/QC requirements.

If you determine CO_2 emissions using the carbon input procedure in § 98.333(b)(1) and (b)(2), you must meet the requirements specified in paragraphs (a) and (b) of this section.

(a) Determine the mass of each solid carbon-containing input material consumed using facility instruments, procedures, or records used for accounting purposes including direct measurement weighing or through the use of purchase records same plant instruments or procedures that are used for accounting purposes (such as weigh hoppers, belt weigh feeders, weighed purchased quantities in shipments or containers, combination of bulk density and volume measurements, etc.). Record the total mass for the materials consumed each calendar month and sum the monthly mass to determine the annual mass for each input material.

(b) For each input material identified in paragraph (a) of this section, you must determine the average carbon content of the material consumed or used in the calendar year using the methods specified in either paragraph (b)(1) or (b)(2) of this section.

(1) Information provided by your material supplier.

(2) Collecting and analyzing at least three representative samples of the material using the appropriate testing method. For each carbon-containing

input material identified for which the carbon content is not provided by your material supplier, the carbon content of the material must be analyzed at least annually using the appropriate standard methods (and their QA/QC procedures), which are identified in paragraphs (b)(2)(i) through (b)(2)(iii) of this section, as applicable. If you document that a specific process input or output contributes less than one percent of the total mass of carbon into or out of the process, you do not have to determine the monthly mass or annual carbon content of that input or output.

(i) Using ASTM E1941–04 Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys (incorporated by reference, see § 98.7), analyze zinc bearing materials.

(ii) Using ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see § 98.7), analyze carbonaceous reducing agents and carbon electrodes.

(iii) Using ASTM C25–06 Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime (incorporated by reference, see § 98.7), analyze flux materials such as limestone or dolomite.

§ 98.335 Procedures for estimating missing data.

For the carbon input procedure in § 98.333(b), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., raw materials carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For missing records of the carbon content of inputs for facilities that estimate emissions using the carbon input procedure in § 98.333(b); 100 percent data availability is required. You must repeat the test for average carbon contents of inputs according to the procedures in § 98.335(b) if data are missing.

(b) For missing records of the annual mass of carbon-containing inputs using the carbon input procedure in § 98.333(b), the substitute data value must be based on the best available estimate of the mass of the input material from all available process data or information used for accounting purposes, such as purchase records.

§ 98.336 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable, for each Waelz kiln or electrothermic furnace.

(a) If a CEMS is used to measure CO_2 emissions, then you must report under this subpart the relevant information required for the Tier 4 Calculation Methodology in § 98.37 and the information listed in this paragraph (a):

(1) Annual zinc product production capacity (tons).

(2) Annual production quantity for each zinc product (tons).

(3) Annual facility production quantity for each zinc product (tons).

(4) Number of Waelz kilns at each facility used for zinc production.

(5) Number of electrothermic furnaces at each facility used for zinc production.

(b) If a CEMS is not used to measure CO_2 emissions, then you must report the information listed in this paragraph (b):

(1) Kiln identification number and annual process CO_2 emissions from each individual Waelz kiln or electrothermic furnace (metric tons).

(2) Annual zinc product production capacity (tons).

(3) Annual production quantity for each zinc product (tons).

(4) Number of Waelz kilns at each facility used for zinc production.

(5) Number of electrothermic furnaces at each facility used for zinc production.

(6) Annual mass of each carbon-containing input material charged to each kiln or furnace (including zinc bearing material, flux materials (e.g., limestone, dolomite), carbon electrode, and other carbonaceous materials (e.g., coal, coke)) (tons).

(7) Carbon content of each carbon-containing input material charged to each kiln or furnace (including zinc bearing material, flux materials, and other carbonaceous materials) from the annual carbon analysis for each kiln or furnace (percent by weight, expressed as a decimal fraction).

(8) Whether carbon content of each carbon-containing input material charged to each kiln or furnace is based on reports from the supplier or through self measurement using applicable ASTM standard method.

(9) If carbon content of each carbon-containing input material charged to each kiln or furnace is based on self measurement, the ASTM Standard Test Method used.

(10) Carbon content of the carbon electrode used in each furnace from the annual carbon analysis (percent by weight, expressed as a decimal fraction).

(11) Whether carbon content of the carbon electrode used in each furnace is based on reports from the supplier or through self measurement using applicable ASTM standard method.

(12) If carbon content of carbon electrode used in each furnace is based on self measurement, the ASTM standard method used.

(13) If you use the missing data procedures in § 98.335(b), you must report how the monthly mass of carbon-containing materials with missing data was determined and the number of months the missing data procedures were used.

§ 98.337 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) through (b) of this section for each zinc production facility.

(a) If a CEMS is used to measure emissions, then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in § 98.37 and the information listed in this paragraph (a):

(1) Monthly facility production quantity for each zinc product (tons).

(2) Annual operating hours for all Waelz kilns and electrothermic furnaces used in zinc production.

(b) If a CEMS is not used to measure emissions, you must also retain the records specified in paragraphs (b)(1) through (b)(7) of this section.

(1) Records of all analyses and calculations conducted for data reported as listed in § 98.336(b).

(2) Annual operating hours for Waelz kilns and electrothermic furnaces used in zinc production.

(3) Monthly production quantity for each zinc product (tons).

(4) Monthly mass of zinc bearing materials, flux materials (e.g., limestone, dolomite), and carbonaceous materials (e.g., coal, coke) charged to the kiln or furnace (tons).

(5) Sampling and analysis records for carbon content of zinc bearing materials, flux materials (e.g., limestone, dolomite), carbonaceous materials (e.g., coal, coke), charged to the kiln or furnace (percent by weight, expressed as a decimal fraction).

(6) Monthly mass of carbon electrode consumed in for each electrothermic furnace (tons).

(7) Sampling and analysis records for carbon content of electrode materials.

(8) You must keep records that include a detailed explanation of how company records of measurements are used to estimate the carbon input to each Waelz kiln or electrothermic furnace, as applicable to your facility, including documentation of any materials excluded from Equation GG–

1 of this subpart that contribute less than 1 percent of the total carbon inputs to the process. You also must document the procedures used to ensure the accuracy of the measurements of materials fed, charged, or placed in an affected unit including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§ 98.338 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart HH—Municipal Solid Waste Landfills

§ 98.340 Definition of the source category.

(a) This source category applies to municipal solid waste (MSW) landfills that accepted waste on or after January 1, 1980.

(b) This source category does not include hazardous waste landfills, construction and demolition landfills, or industrial landfills.

(c) This source category consists of the following sources at municipal solid waste (MSW) landfills: Landfills, landfill gas collection systems, and landfill gas destruction devices (including flares).

§ 98.341 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a MSW landfill and the facility meets the requirements of § 98.2(a)(1).

§ 98.342 GHGs to report.

(a) You must report CH_4 generation and CH_4 emissions from landfills.

(b) You must report CH_4 destruction resulting from landfill gas collection and combustion systems.

(c) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary combustion unit following the requirements of subpart C.

§ 98.343 Calculating GHG emissions.

(a) For all landfills subject to the reporting requirements of this subpart, calculate annual modeled CH_4 generation according to the applicable requirements in paragraphs (a)(1) through (a)(3) of this section.

(1) Calculate annual modeled CH_4 generation using Equation HH–1 of this section.

$$G_{CH4} = \left[\sum_{x=S}^{T-1} \left\{ W_x L_{0,x} \left(e^{-k(T-x-1)} - e^{-k(T-x)} \right) \right\} \right] \quad \text{(Eq. HH-1)}$$

Where:

G_{CH4} = Modeled methane generation rate in reporting year T (metric tons CH_4).

X = Year in which waste was disposed.

S = Start year of calculation. Use the year 50 years prior to the year of the emissions estimate, or the opening year of the landfill, whichever is more recent.

T = Reporting year for which emissions are calculated.

W_x = Quantity of waste disposed in the landfill in year X from tipping fee receipts or other company records (metric tons, as received (wet weight)).

L_0 = CH_4 generation potential (metric tons CH_4/metric ton waste) = MCF × DOC × DOC_F × F × 16/12.

MCF = Methane correction factor (fraction); default is 1.

DOC = Degradable organic carbon from Table HH–1 of this subpart or measurement data, if available [fraction (metric tons C/metric ton waste)].

DOC_F = Fraction of DOC dissimilated (fraction); default is 0.5.

F = Fraction by volume of CH_4 in landfill gas from measurement data, if available (fraction); default is 0.5.

k = Rate constant from Table HH–1 of this subpart or measurement data, if available (yr^{-1}).

(2) For years when material-specific waste quantity data are available, apply Equation HH–1 of this section for each waste quantity type and sum the CH_4 generation rates for all waste types to calculate the total modeled CH_4 generation rate for the landfill. Use the appropriate parameter values for k, DOC, MCF, DOC_F, and F shown in Table HH–1 of this subpart. The annual quantity of each type of waste disposed must be calculated as the sum of the daily quantities of waste (of that type) disposed. You may use the bulk waste parameters for a portion of your waste materials when using the material-specific modeling approach for mixed waste streams that cannot be designated to a specific material type. For years when waste composition data are not available, use the bulk waste parameter values for k and L_0 in Table HH–1 of this subpart for the total quantity of waste disposed in those years.

(3) For years prior to reporting for which waste disposal quantities are not readily available, W_x shall be estimated using one of the applicable methods in paragraphs (a)(3)(i) through (a)(3)(iii) of this section. You must determine which method is most applicable to the conditions and disposal history of your facility and use that method to estimate waste disposal quantities.

(i) Assume all prior year waste disposal quantities are the same as the waste quantity in the first reporting year.

(ii) Use the estimated population served by the landfill in each year, the values for national average per capita waste generation, and fraction of generated waste disposed of in solid waste disposal sites found in Table HH–2 of this subpart, and calculate the waste quantity landfilled using Equation HH–2 of this section.

$$W_x = POP_x \times WGR_x \times \frac{\%SWDS_x}{100\%} \quad \text{(Eq. HH-2)}$$

Where:

W_x = Quantity of waste placed in the landfill in year × (metric tons, wet basis).

POP_x = Population of served by the landfill in year × from city population, census data, or other estimates (capita).

WGR = Average per capita waste generation rate for year x from Table HH–2 of this subpart (metric tons per capita per year, wet basis; tons/cap/yr).

%SWDS = Percent of waste generated subsequently managed in solid waste disposal sites (i.e., landfills) for year × from Table HH–2 of this subpart.

(iii) Use a constant average waste disposal quantity calculated using Equation HH–3 of this section for each year the landfill was in operation (i.e., from first accepting waste until the last year for which waste disposal data is unavailable, inclusive).

$$WAR = \frac{LFC}{(YrData - YrOpen + 1)} \qquad \text{(Eq. HH-3)}$$

Where:

WAR = Annual average waste acceptance rate (metric tons per year).

LFC = Landfill capacity or, for operating landfills, capacity of the landfill currently used from design drawings or engineering estimates (metric tons).

YrData = Year in which the landfill last received waste or, for operating landfills, the year prior to the first reporting year when waste disposal data is first available from company records, or best available data.

YrOpen = Year in which the landfill first received waste from company records or best available data. If no data are available for estimating YrOpen for a closed landfill, use 30 years as the default operating life of the landfill.

(b) For landfills with gas collection systems, calculate the quantity of CH_4 destroyed according to the requirements in paragraphs (b)(1) and (b)(2) of this section.

(1) If you continuously monitor the flow rate, CH_4 concentration, temperature, pressure, and moisture content of the landfill gas that is collected and routed to a destruction device (before any treatment equipment) using a monitoring meter specifically for CH_4 gas, as specified in § 98.344, you must use this monitoring system and calculate the quantity of CH_4 recovered for destruction using Equation HH–4 of this section. A fully integrated system that directly reports CH_4 content requires no other calculation than summing the results of all monitoring periods for a given year.

$$R = \sum_{n=1}^{N}\left((V)_n \times \left[1 - \left(f_{H20}\right)_n\right] \times \frac{(C)_n}{100\%} \times 0.0423 \times \frac{520^{o}R}{(T)_n} \times \frac{(P)_n}{1\ atm} \times 1{,}440 \times \frac{0.454}{1{,}000} \right) \qquad \text{(Eq. HH-4)}$$

Where:

R = Annual quantity of recovered CH_4 (metric tons CH_4).

N = Total number of measurement periods in a year. Use daily averaging periods for continuous monitoring system (N = 365). For weekly sampling, use N = 52.

n = Index for measurement period.

$(V)_n$ = Daily average volumetric flow rate for day n (acfm). If the flow rate meter automatically corrects for temperature and pressure, replace ''520 °R/$(T)_n \times (P)_n$/1 atm'' with ''1''. If the CH_4 concentration is determined on a dry basis and the flow rate meter automatically corrects for moisture/content, replace the term $[1 - (f_{H_2O})_n]$ with 1.

$(f_{H_2O})_n$ = Daily average moisture content of landfill gas, volumetric basis (cubic feet water per cubic feet landfill gas).

$(C)_n$ = Daily average CH_4 concentration of landfill gas for day n (volume %, dry basis). If the CH_4 concentration is determined on a wet basis, replace the term $[1 - (f_{H_2O})_n]$ with 1.

0.0423 = Density of CH_4 lb/cf at 520 °R or 60 °F and 1 atm.

$(T)_n$ = Temperature at which flow is measured for day n (°R).

$(P)_n$ = Pressure at which flow is measured for day n (atm).

1,440 = Conversion factor (min/day).

0.454/1,000 = Conversion factor (metric ton/lb).

(2) If you do not continuously monitor according to paragraph (b)(1) of this section, you must determine the flow rate, CH_4 concentration, temperature, pressure, and moisture content of the landfill gas that is collected and routed to a destruction device (before any treatment equipment) at least weekly according to the requirements in paragraphs (b)(2)(i) through (b)(2)(iii) of this section and calculate the quantity of CH_4 recovered for destruction using Equation HH–4 of this section.

(i) Continuously monitor gas flow rate and determine the cumulative volume of landfill gas each week and the cumulative volume of landfill gas each year that is collected and routed to a destruction device (before any treatment equipment). Under this option, the gas flow meter is not required to automatically correct for temperature, pressure, or, if necessary, moisture content. If the gas flow meter is not equipped with automatic correction for temperature, pressure, or, if necessary, moisture content, you must determine these parameters as specified in paragraph (b)(2)(iii) of this section.

(ii) Determine the CH_4 concentration in the landfill gas that is collected and routed to a destruction device (before any treatment equipment) in a location near or representative of the location of the gas flow meter no less than weekly.

(iii) If the gas flow meter is not equipped with automatic correction for temperature, pressure, or, if necessary, moisture content:

(A) Determine the temperature, pressure in the landfill gas that is collected and routed to a destruction device (before any treatment equipment) in a location near or representative of the location of the gas flow meter no less than weekly.

(B) If the CH_4 concentration is determined on a dry basis, determine the moisture content in the landfill gas that is collected and routed to a destruction device (before any treatment equipment) in a location near or representative of the location of the gas flow meter no less than weekly

(c) Calculate CH_4 generation (adjusted for oxidation in cover materials) and actual CH_4 emissions (taking into account any CH_4 recovery, and oxidation in cover materials) according to the applicable methods in paragraphs (c)(1) through (c)(3) of this section.

(1) Calculate CH_4 generation, adjusted for oxidation, from the modeled CH_4 (G_{CH_4} from Equation HH–1 of this section) using Equation HH–5 of this section.

$$MG = G_{CH4} \times (1 - OX) \qquad \text{(Eq. HH-5)}$$

Where:

MG = Methane generation, adjusted for oxidation, from the landfill in the reporting year (metric tons CH_4).

G_{CH4} = Modeled methane generation rate in reporting year from Equation HH–1 of this section (metric tons CH_4).

OX = Oxidation fraction. Use the default value of 0.1 (10%).

(2) For landfills that do not have landfill gas collection systems, the CH_4 emissions are equal to the CH_4 generation (MG) calculated in Equation HH–5 of this section.

(3) For landfills with landfill gas collection systems, calculate CH_4 emissions using the methodologies specified in paragraphs (c)(3)(i) and (c)(3)(ii) of this section.

(i) Calculate CH_4 emissions from the modeled CH_4 generation and measured CH_4 recovery using Equation HH–6 of this section.

$$\text{Emissions} = \left[\left(G_{CH4} - R\right) \times \left(1 - OX\right) + R \times \left(1 - \left(DE \times f_{Dest}\right)\right)\right] \qquad \text{(Eq. HH-6)}$$

Where:

Emissions = Methane emissions from the landfill in the reporting year (metric tons CH_4).

G_{CH_4} = Modeled methane generation rate in reporting year from Equation HH–1 of this section or the quantity of recovered CH_4 from Equation HH–4 of this section, whichever is greater (metric tons CH_4).

R = Quantity of recovered CH_4 from Equation HH–4 of this section (metric tons).

OX = Oxidation fraction. Use the oxidation fraction default value of 0.1 (10%).

DE = Destruction efficiency (lesser of manufacturer's specified destruction efficiency and 0.99). If the gas is transported off-site for destruction, use DE = 1.

f_{Dest} = Fraction of hours the destruction device was operating (annual operating hours/8760 hours per year). If the gas is destroyed in a back-up flare (or simlar device) or if the gas is transported off-site for destruction, use f_{Dest} = 1.

(ii) Calculate CH_4 generation and CH_4 emissions using measured CH_4 recovery and estimated gas collection efficiency and Equations HH–7 and HH–8 of this section.

$$MG = \frac{R}{CE \times f_{Rec}} \times (1 - OX) \qquad \text{(Eq. HH-7)}$$

$$\text{Emissions} = \left[\left(\frac{R}{CE \times f_{Rec}} - R\right) \times \left(1 - OX\right) + R \times \left(1 - \left(DE \times f_{Dest}\right)\right)\right] \qquad \text{(Eq. HH-8)}$$

Where:

MG = Methane generation, adjusted for oxidation, from the landfill in the reporting year (metric tons CH_4).

Emissions = Methane emissions from the landfill in the reporting year (metric tons CH_4).

R = Quantity of recovered CH_4 from Equation HH–4 of this section (metric tons CH_4).

CE = Collection efficiency estimated at landfill, taking into account system coverage, operation, and cover system materials from Table HH–3 of this subpart. If area by soil cover type information is not available, use default value of 0.75 (CE4 in table HH–3 of this subpart) for all areas under active influence of the collection system.

f_{Rec} = Fraction of hours the recovery system was operating (annual operating hours/8760 hours per year).

OX = Oxidation fraction. Use the oxidation fractions default value of 0.1 (10%).

DE = Destruction efficiency, (lesser of manufacturer's specified destruction efficiency and 0.99). If the gas is transported off-site for destruction, use DE = 1.

f_{Dest} = Fraction of hours the destruction device was operating (device operating hours/8760 hours per year). If the gas is destroyed in a back-up flare (or similar device) or if the gas is transported off-site for destruction, use f_{Dest} = 1.

§ 98.344 Monitoring and QA/QC requirements.

(a) The quantity of waste landfilled must be determined using mass measurement equipment meeting the requirements for commercial weighing equipment as described in ''Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices'' NIST Handbook 44 (2009)(incorporated by reference, see § 98.7).

(b) For landfills with gas collection systems, install, operate, maintain, and calibrate a gas composition monitor capable of measuring the concentration of CH4 in the recovered landfill gas using one of the methods specified in paragraphs (b)(1) through (b)(6) of this section or as specified by the manufacturer. Gas composition monitors shall be calibrated prior to the first reporting year and recalibrated either annually or at the minimum frequency specified by the manufacturer, whichever is more frequent, or whenever the error in the midrange calibration check exceeds ± 10 percent.

(1) Method 18 at 40 CFR part 60, appendix A–6.

(2) ASTM D1945–03, Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, *see* § 98.7).

(3) ASTM D1946–90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, *see* § 98.7).

(4) GPA Standard 2261–00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.

(5) UOP539–97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see § 98.7).

(6) As an alternative to the gas chromatography methods provided in paragraphs (b)(1) through (b)(5) of this section, you may use total gaseous organic concentration analyzers and calculate the methane concentration following the requirements in paragraphs (b)(6)(i) through (b)(6)(iii) of this section.

(i) Use Method 25A or 25B at 40 CFR part 60, appendix A–7 to determine total gaseous organic concentration. You must calibrate the instrument with methane and determine the total gaseous organic concentration as carbon (or as methane; K=1 in Equation 25A–1 of Method 25A at 40 CFR part 60, appendix A–7).

(ii) Determine a non-methane organic carbon correction factor no less frequently than once a reporting year following the requirements in paragraphs (b)(6)(ii)(A) through (b)(6)(ii)(C) of this section.

(A) Take a minimum of three grab samples of the landfill gas that is collected and routed to a destruction device (before any treatment equipment) with a minimum of 20 minutes between samples and determine the methane composition of the landfill gas using one of the methods specificed in paragraphs (b)(1) through (b)(5) of this section.

(B) As soon as practical after each grab sample is collected and prior to the collection of a subsequent grab sample, determine the total gaseous organic concentration of the landfilll gas that is collected and routed to a destruction device (before any treatment equipment) using either Method 25A or 25B at 40 CFR part 60, appendix A–7 as specified in paragaph (b)(6)(i) of this section.

(C) Determine the arithmetic average methane concentration and the arithmetic average total gaseous organic concentration of the samples analyzed according to paragraphs (b)(6)(ii)(A) and (b)(6)(ii)(B) of this section, respectively, and calculate the non-methane organic carbon correction factor as the ratio of the average methane concentration to the average total gaseous organic concentration. If the ratio exceeds 1, use 1 for the non-methane organic carbon correction factor.

(iii) Calculate the methane concentration as specified in Equation HH–9 of this section.

$$C_{CH4} = f_{NMOC} \times C_{TGOC} \qquad \text{(Eq. HH-9)}$$

Where:

C_{CH4} = Methane concentration in the landfill gas (volume %).

f_{NMOC} = Non-methane organic carbon correction factor from the most recent determination of the non-methane organic carbon correction factor as specified in paragraph (b)(6)(ii) of this section (unitless).

C_{TGOC} = Total gaseous organic carbon concentration measured using Method 25A or 25B at 40 CFR part 60, appendix A–7 during routine monitoring of the landfill gas (volume %).

(c) For landfills with gas collection systems, install, operate, maintain, and calibrate a gas flow meter capable of measuring the volumetric flow rate of the recovered landfill gas using one of the methods specified in paragraphs (c)(1) through (c)(8) of this section or as specified by the manufacturer. Each gas flow meter shall be calibrated prior to the first year of reporting and recalibrated either biennially (every 2 years) or at the minimum frequency specified by the manufacturer. Except as provided in § 98.343(b)(2)(i), each gas flow meter must be capable of correcting for the temperature and pressure and, if the gas composition monitor determines CH_4 concentration on a dry basis, moisture content.

(1) ASME MFC–3M–2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, *see* § 98.7).

(2) ASME MFC–4M–1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters (incorporated by reference, *see* § 98.7).

(3) ASME MFC–6M–1998, Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, *see* § 98.7).

(4) ASME MFC–7M–1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, *see* § 98.7).

(5) ASME MFC–11M–2006 Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters (incorporated by reference, *see* § 98.7). The mass flow must be corrected to volumetric flow based on the measured temperature, pressure, and gas composition.

(6) ASME MFC–14M–2003 Measurement of Fluid Flow Using Small Bore Precision Orifice Meters (incorporated by reference, *see* § 98.7).

(7) ASME MFC–18M–2001 Measurement of Fluid Flow using Variable Area Meters (incorporated by reference, *see* § 98.7).

(8) Method 2A or 2D at 40 CFR part 60, appendix A–1.

(d) All temperature and pressure monitors must be calibrated using the procedures and frequencies specified by the manufacturer.

(e) The owner or operator shall document the procedures used to ensure the accuracy of the estimates of disposal quantities and, if applicable, gas flow rate, gas composition, temperature, and pressure measurements. These procedures include, but are not limited to, calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

§ 98.345 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the requirements in paragraphs (a) through (c) of this section.

(a) For each missing value of the CH_4 content, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the ''after'' value is not obtained by the end of the reporting year, you may use the ''before'' value for the missing data substitution. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(b) For missing gas flow rates, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the ''after'' value is not obtained by the end of the reporting year, you may use the ''before'' value for the missing data substitution. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(c) For missing daily waste disposal quantity data for disposal in reporting years, the substitute value shall be the average daily waste disposal quantity for that day of the week as measured on the week before and week after the missing daily data.

§ 98.346 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information for each landfill.

(a) A classification of the landfill as ''open'' (actively received waste in the reporting year) or ''closed'' (no longer receiving waste), the year in which the landfill first started accepting waste for disposal, the last year the landfill accepted waste (for open landfills, enter the estimated year of landfill closure), the capacity (in metric tons) of the landfill, an indication of whether leachate recirculation is used, and the waste disposal quantity for each year of landfilling.

(b) Method for estimating waste disposal quantity, and reason for its selection.

(c) Waste composition for each year of landfilling, if available, in percentage categorized as:

(1) Municipal.

(2) Biosolids or biological sludges.

(3) Other, or more refined categories, such as those for which k rates are available in Table HH–1 of this subpart, and the method or basis for estimating waste composition.

(d) For each waste type used to calculate CH_4 generation using Equation HH–1 of this subpart, you must report:

(1) Degradable organic carbon (DOC) value used in the calculations.

(2) Decay rate (k) value used in the calculations.

(e) Fraction of CH_4 in landfill gas (F) and an indication of whether the fraction of CH_4 was determined based on measured values or the default value.

(f) The surface area of the landfill containing waste (in square meters), the cover types applicable to the landfill, the surface area and oxidation fraction for each cover type used to calculate the average oxidation fraction, and the average oxidation fraction used in the calculations.

(g) The modeled annual methane generation rate for the reporting year (metric tons CH_4) calculated using Equation HH–1 of this subpart.

(h) For landfills without gas collection systems, the annual methane emissions (i.e., the methane generation, adjusted for oxidation, calculated using Equation HH–5 of this subpart), reported in metric tons CH_4.

(i) For landfills with gas collection systems, you must report:

(1) Total volumetric flow of landfill gas collected for destruction (cubic feet at 520 °R or 60 °F and 1 atm).

(2) CH_4 concentration of landfill gas collected for destruction (percent by volume).

(3) Monthly average temperature for each month at which flow is measured for landfill gas collected for destruction, or statement that temperature is incorporated into internal calculations run by the monitoring equipment.

(4) Monthly average pressure for each month at which flow is measured for landfill gas collected for destruction, or statement that temperature is incorporated into internal calculations run by the monitoring equipment.

(5) An indication of whether destruction occurs at the landfill facility or off-site. If destruction occurs at the landfill facility, also report an indication of whether a back-up destruction device is present at the landfill, the annual operating hours for the primary destruction device, the annual operating hours for the back-up destruction device (if present), and the destruction efficiency used (percent).

(6) Annual quantity of recovered CH_4 (metric tons CH_4) calculated using Equation HH–4 of this subpart.

(7) A description of the gas collection system (manufacture, capacity, number of wells, etc.), the surface area (square meters) and estimated waste depth (meters) for each area specified in Table HH–3 of this subpart, the estimated gas collection system efficiency for landfills with this gas collection system, and the annual operating hours of the gas collection system.

(8) Methane generation corrected for oxidation calculated using Equation HH–5 of this subpart, reported in metric tons CH_4.

(9) Methane generation (G_{CH4}) value used as an input to Equation HH–6 of this subpart. Specify whether the value is modeled (G_{CH4} from HH–1 of this subpart) or measured (R from Equation HH–4 of this subpart).

(10) Methane generation corrected for oxidation calculated using Equation HH–7 of this subpart, reported in metric tons CH_4.

(11) Methane emissions calculated using Equation HH–6 of this subpart, reported in metric tons CH_4.

(12) Methane emissions calculated using Equation HH–8 of this subpart, reported in metric tons CH_4.

§ 98.347 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the calibration records for all monitoring equipment, including the method or manufacturer's specification used for calibration.

§ 98.348 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE HH–1 TO SUBPART HH OF PART 98—EMISSIONS FACTORS, OXIDATION FACTORS AND METHODS

Factor	Default value	Units
Waste model—bulk waste option		
k (precipitation <20 inches/year and no leachate recirculation)	0.02	yr^{-1}
k (precipitation 20–40 inches/year and no leachate recirculation).	0.038	yr^{-1}
k (precipitation >40 inches/year or for landfill areas with leachate recirculation).	0.057	yr^{-1}
L_0 (Equivalent to DOC = 0.2028 when MCF = 1, DOC_F = 0.5, and F = 0.5).	0.067	metric tons CH_4/metric ton waste
Waste model—All MSW landfills		
MCF	1	
DOC_F	0.5	
F	0.5	
Waste model—MSW using waste composition option		
DOC (food waste)	0.15	Weight fraction, wet basis
DOC (garden)	0.2	Weight fraction, wet basis
DOC (paper)	0.4	Weight fraction, wet basis
DOC (wood and straw)	0.43	Weight fraction, wet basis
DOC (textiles)	0.24	Weight fraction, wet basis
DOC (diapers)	0.24	Weight fraction, wet basis
DOC (sewage sludge)	0.05	Weight fraction, wet basis
DOC (bulk waste)	0.20	Weight fraction, wet basis
k (food waste)	0.06 to 0.185[a]	yr^{-1}
k (garden)	0.05 to 0.10[a]	yr^{-1}
k (paper)	0.04 to 0.06[a]	yr^{-1}
k (wood and straw)	0.02 to 0.03[a]	yr^{-1}
k (textiles)	0.04 to 0.06[a]	yr^{-1}
k (diapers)	0.05 to 0.10[a]	yr^{-1}
k (sewage sludge)	0.06 to 0.185[a]	yr^{-1}
Calculating methane generation and emissions		
OX	0.1	

TABLE HH–1 TO SUBPART HH OF PART 98—EMISSIONS FACTORS, OXIDATION FACTORS AND METHODS—Continued

Factor	Default value	Units
DE	0.99	

[a] Use the lesser value when the potential evapotranspiration rate exceeds the mean annual precipitation rate and leachate recirculation is not used. Use the greater value when the potential evapotranspiration rate does not exceed the mean annual precipitation rate or when leachate recirculation is used.

TABLE HH–2 TO SUBPART HH OF PART 98—U.S. PER CAPITA WASTE DISPOSAL RATES

Year	Waste per capita ton/cap/yr	% to SWDS
1950	0.63	100
1951	0.63	100
1952	0.63	100
1953	0.63	100
1954	0.63	100
1955	0.63	100
1956	0.63	100
1957	0.63	100
1958	0.63	100
1959	0.63	100
1960	0.63	100
1961	0.64	100
1962	0.64	100
1963	0.65	100
1964	0.65	100
1965	0.66	100
1966	0.66	100
1967	0.67	100
1968	0.68	100
1969	0.68	100
1970	0.69	100
1971	0.69	100
1972	0.70	100
1973	0.71	100
1974	0.71	100
1975	0.72	100
1976	0.73	100
1977	0.73	100
1978	0.74	100
1979	0.75	100
1980	0.75	100
1981	0.76	100
1982	0.77	100
1983	0.77	100
1984	0.78	100
1985	0.79	100
1986	0.79	100
1987	0.80	100
1988	0.80	100
1989	0.85	84
1990	0.84	77
1991	0.78	76
1992	0.76	72
1993	0.78	71
1994	0.77	67
1995	0.72	63
1996	0.71	62
1997	0.72	61
1998	0.78	61
1999	0.78	60
2000	0.84	61
2001	0.95	63
2002	1.06	66
2003	1.06	65
2004	1.06	64
2005	1.06	64
2006	1.06	64

TABLE HH–3 TO SUBPART HH OF PART 98—LANDFILL GAS COLLECTION EFFICIENCIES

Description	Landfill Gas Collection Efficiency
A1: Area with no waste in-place	Not applicable; do not use this area in the calculation.
A2: Area without active gas collection, regardless of cover type	CE2: 0%.
H2: Average depth of waste in area A2	
A3: Area with daily soil cover and active gas collection	CE3: 60%.
H3: Average depth of waste in area A3	
A4: Area with an intermediate soil cover and active gas collection	CE4: 75%.
H4: Average depth of waste in area A4	
A5: Area with a final soil and geomembrane cover system and active gas collection.	CE5: 95%.
H5: Average depth of waste in area A5	
Area weighted average collection efficiency for landfills	CEave1 = (A2*CE2 + A3*CE3 + A4*CE4 + A5*CE5)/(A2+A3+A4+A5).

Subpart II—[Reserved]

Subpart JJ—Manure Management

§ 98.360 Definition of the source category.

(a) This source category consists of livestock facilities with manure management systems that emit 25,000 metric tons CO_2e or more per year.

(1) Table JJ–1 presents the minimum average annual animal population by animal group that is estimated to emit 25,000 metric tons CO_2e or more per year. Facilities with an average annual animal population, as described in § 98.363(a)(1) and (2), below those listed in Table JJ–1 do not need to report under this rule. A facility with an annual animal population that exceeds those listed in Table JJ–1 should conduct a more thorough analysis to determine applicability.

(2) (i) If a facility has more than one animal group present (e.g., swine and poultry), the facility must determine if they are required to report by calculating the combined animal group factor (CAGF) using equation JJ–1:

$$CAGF = \sum_{\text{Animal Groups}} \left(\frac{AAAP_{AG,\ Facility}}{APTL_{AG}} \right) \qquad \text{(Eq. JJ-1)}$$

Where:

CAGF = Combined Animal Group Factor

$AAAP_{AG,Facility}$ = Average annual animal population at the facility, by animal group

$APTL_{AG}$ = Animal population threshold level, as specified in Table JJ–1 of this section

(ii) If the calculated CAGF for a facility is less than 1, the facility is not required to report under this rule. If the CAGF is equal to or greater than 1, the facility must use more detailed applicability tables and tools to determine if they are required to report under this rule.

(b) A manure management system (MMS) is a system that stabilizes and/or stores livestock manure, litter, or manure wastewater in one or more of the following system components: Uncovered anaerobic lagoons, liquid/slurry systems with and without crust covers (including but not limited to ponds and tanks), storage pits, digesters, solid manure storage, dry lots (including feedlots), high-rise houses for poultry production (poultry without litter), poultry production with litter, deep bedding systems for cattle and swine, manure composting, and aerobic treatment.

(c) This source category does not include system components at a livestock facility that are unrelated to the stabilization and/or storage of manure such as daily spread or pasture/range/paddock systems or land application activities or any method of manure utilization that is not listed in § 98.360(b).

(d) This source category does not include manure management activities located off site from a livestock facility or off-site manure composting operations.

§ 98.361 Reporting threshold.

Livestock facilities must report GHG emissions under this subpart if the facility meets the reporting threshold as defined in 98.360(a) above, contains a manure management system as defined in 98.360(b) above, and meets the requirements of § 98.2(a)(1).

§ 98.362 GHGs to report.

(a) Livestock facilities must report annual aggregate CH_4 and N_2O emissions for the following MMS components at the facility:

(1) Uncovered anaerobic lagoons.

(2) Liquid/slurry systems (with and without crust covers, and including but not limited to ponds and tanks).

(3) Storage pits.

(4) Digesters, including covered anaerobic lagoons.

(5) Solid manure storage.

(6) Dry lots, including feedlots.

(7) High-rise houses for poultry production (poultry without litter)

(8) Poultry production with litter.

(9) Deep bedding systems for cattle and swine.

(10) Manure composting.

(11) Aerobic treatment.

(b) A livestock facility that is subject to this rule only because of emissions from manure management system components is not required to report emissions from subparts C through PP (other than subpart JJ) of this part.

(c) A livestock facility that is subject to this part because of emissions from source categories described in subparts C through PP of this part is not required to report emissions under subpart JJ of this part unless emissions from manure management systems are 25,000 metric tons CO_2e per year or more.

§ 98.363 Calculating GHG emissions.

(a) For all manure management system components listed in 98.360(b) except digesters, estimate the annual CH_4 emissions and sum for all the components to obtain total emissions from the manure management system for all animal types using Equation JJ–1.

$$CH_4\ Emissions_{MMS}\ (metric\ tons/yr) = \sum_{animal\ types}\left[\sum_{MMSC}\left[\left(TVS_{AT}\ x\ VS_{MMSC}\ x\ (1-VS_{ss})\ x\ 365\ days/yr\ x\ (B_0)_{AT}\ x\ MCF_{MMSC}\right) x\ 0.662\ kg\ CH_4/m^3\ x\ 1\ metric\ ton/1000\ kg\right]\right] \quad (Eq.\ JJ\text{-}2)$$

Where:

MMSC = Manure management systems component.

TVS_{AT} = Total volatile solids excreted by animal type, calculated using Equation JJ–3 of this section (kg/day).

VS_{MMSC} = Fraction of the total manure for each animal type that is managed in MMS component MMSC, assumed to be equivalent to the fraction of VS in each MMS component.

VS_{ss} = Volatile solids removal through solid separation; if solid separation occurs prior to the MMS component, use a default value from Table JJ–4 of this section; if no solid separation occurs, this value is set to 0.

$(B_0)_{AT}$ = Maximum CH_4-producing capacity for each animal type, as specified in Table JJ–2 of this section (m^3 CH_4/kg VS).

MCF_{MMSC} = CH_4 conversion factor for the MMS component, as specified in Table JJ–5 of this section (decimal).

$$TVS_{AT} = Population_{AT} \times TAM_{AT} \times VS_{AT}/1000 \quad (Eq.\ JJ\text{-}3)$$

Where:

TVS_{AT} = Daily total volatile solids excreted per animal type (kg/day).

$Population_{AT}$ = Average annual animal population contributing manure to the manure management system by animal type (head) (see description in § 98.363(a)(i) and (ii) below).

TAM_{AT} = Typical animal mass for each animal type, using either default values in Table JJ–2 of this section or farm-specific data (kg/head).

VS_{AT} = Volatile solids excretion rate for each animal type, using default values in Table JJ–2 or JJ–3 of this section (kg VS/day/1000 kg animal mass).

(1) Average annual animal populations for static populations (e.g., dairy cows, breeding swine, layers) must be estimated by performing an animal inventory or review of facility records once each reporting year.

(2) Average annual animal populations for growing populations (meat animals such as beef and veal cattle, market swine, broilers, and turkeys) must be estimated each year using the average number of days each animal is kept at the facility and the number of animals produced annually, and an equation similar or equal to Equation JJ–4 below, adapted from Equation 10.1 in *2006 IPCC Guidelines for National Greenhouse Gas Inventories,* Volume 4, Chapter 10.

$$Population_{AT} = Days\ onsite_{AT} \times \left(\frac{NAPA_{AT}}{365}\right) \quad (Eq.\ JJ\text{-}4)$$

Where:

$Population_{AT}$ = Average annual animal population (by animal type).

$Days\ onsite_{AT}$ = Average number of days the animal is kept at the facility, by animal type.

$NAPA_{AT}$ = Number of animals produced annually, by animal type.

(b) For each digester, calculate the total amount of CH_4 emissions, and then sum the emissions from all digesters, as shown in Equation JJ–5 of this section.

$$H_4\ Emissions_{AD} = \sum_{1}^{AD}\left(CH_4C - CH_4D + CH_4L\right) \quad (Eq.\ JJ\text{-}5)$$

Where:

CH_4 $Emissions_{AD}$ = CH_4 emissions from anaerobic digestion (metric tons/yr).

AD = Number of anaerobic digesters at the manure management facility.

CH_4C = CH_4 flow to digester combustion device, calculated using Equation JJ–6 of this section (metric tons CH_4/yr).

CH_4D = CH_4 destruction at digesters, calculated using Equation JJ–11 of this section (metric tons CH_4/yr) .

CH_4L = Leakage at digesters calculated using Equation JJ–12 of this section (metric tons CH_4/yr).

(1) For each digester, calculate the annual CH_4 flow to the combustion device (CH_4C) using Equation JJ–6 of this section. A fully integrated system that directly reports the quantity of CH_4 flow to the digester combustion device requires only summing the results of all monitoring periods for a given year to obtain CH_4C.

$$CH_4C = \left(V \times \frac{C}{100\%} \times 0.0423 \times \frac{520^oR}{T} \times \frac{P}{1\ atm} \times \frac{0.454\ metric\ ton}{1{,}000\ pounds}\right) \quad (Eq.\ JJ\text{-}6)$$

Where:

CH_4C = CH_4 flow to digester combustion device (metric tons CH_4/yr).

V = Average annual volumetric flow rate, calculated in Equation JJ–7 of this subsection (cubic feet CH_4/yr).

C = Average annual CH_4 concentration of digester gas, calculated in Equation JJ–8 of this section (%, wet basis).

0.0423 = Density of CH_4 lb/scf (at 520 °R or 60 °F and 1 atm).

T = Average annual temperature at which flow is measured, calculated in Equation JJ–9 of this section (°R).

P = Average annual pressure at which flow is measured, calculated in Equation JJ–10 of this section (atm).

(2) For each digester, calculate the average annual volumetric flow rate, CH_4 concentration of digester gas, temperature, and pressure at which flow are measured using Equations JJ–7 through JJ–10 of this section.

$$V = \frac{\sum_{n=1}^{OD}\left(V_n \times \frac{1,440 \text{ minutes}}{\text{day}}\right)}{OD} \qquad \text{(Eq. JJ-7)}$$

Where:

V = Average annual volumetric flow rate (cubic feet CH_4/yr).

OD = Operating days, number of days per year that that the digester was operating (days/yr).

V_n = Daily average volumetric flow rate for day n, as determined from daily monitoring as specified in § 98.364 (acfm).

$$C = \frac{\sum_{n=1}^{OD} C_n}{OD} \qquad \text{(Eq. JJ-8)}$$

Where:

C = Average annual CH_4 concentration of digester gas (%, wet basis).

OD = Operating days, number of days per year that the digester was operating (days/yr).

C_n = Average daily CH_4 concentration of digester gas for day n, as determined from daily monitoring as specified in § 98.364 (%, wet basis).

$$T = \frac{\sum_{n=1}^{OD} T_n}{OD} \qquad \text{(Eq. JJ-9)}$$

Where:

T = Average annual temperature at which flow is measured (°R).

OD = Operating days, number of days per year that the digester was operating (days/yr).

T_n = Temperature at which flow is measured for day n(°R).

$$P = \frac{\sum_{n=1}^{OD} P_n}{OD} \qquad \text{(Eq. JJ-10)}$$

Where:

P = Average annual pressure at which flow is measured (atm).

OD = Operating days, number of days per year that the digester was operating (days/yr).

P_n = Pressure at which flow is measured for day n (atm).

(3) For each digester, calculate the CH_4 destruction at the digester combustion device using Equation JJ–11 of this section.

$$CH_4D = CH_4C \times DE \times OH/Hours \qquad \text{(Eq. JJ-11)}$$

Where:

CH_4D = CH_4 destruction at digester combustion device (metric tons/yr).

CH_4C = Annual quantity of CH_4 flow to digester combustion device, as calculated in Equation JJ–6 of this section (metric tons CH_4).

DE = CH_4 destruction efficiency from flaring or burning in engine (lesser of manufacturer's specified destruction efficiency and 0.99). If the gas is transported off-site for destruction, use DE = 1.

OH = Number of hours combustion device is functioning in reporting year.

Hours = Hours in reporting year.

(4) For each digester, calculate the CH_4 leakage using Equation JJ–12 of this section.

$$CH_4L = CH_4C \times \left(\frac{1}{CE} - 1\right) \qquad \text{(Eq. JJ-12)}$$

Where:

CH_4L = Leakage at digesters (metric tons/yr).

CH_4C = Annual quantity of CH_4 flow to digester combustion device, as calculated in Equation JJ–6 of this section (metric tons CH_4).

CE = CH_4 collection efficiency of anaerobic digester, as specified in Table JJ–6 of this section (decimal).

(c) For each MMS component, estimate the annual N_2O emissions and sum for all MMS components to obtain total emissions from the manure management system for all animal types using Equation JJ–13 of this section.

$$\text{Direct } N_2O \text{ Emissions (metric tons/year)} = \sum_{\text{animal types}} \left[\sum_{MMSC} N_{ex\,AT} \times N_{ex,MMSC} \times (1 - N_{ss}) \times EF_{MMSC} \times 365 \text{ days/yr}\right] \times 44\ N_2O/28\ N_2O{-}N \times 1 \text{ metric ton}/1000 \text{ kg} \qquad \text{(Eq. JJ-13)}$$

Where:

$N_{ex\,AT}$ = Daily total nitrogen excreted per animal type, calculated using Equation JJ–14 of this section (kg N/day).

$N_{ex,MMSC}$ = Fraction of the total manure for each animal type that is managed in MMS component MMSC, assumed to be equivalent to the fraction of N_{ex} in each MMS component.

N_{ss} = Nitrogen removal through solid separation; if solid separation occurs prior to the MMS component, use a default value from Table JJ–4 of this section; if no solid separation occurs, this value is set to 0.

EF_{MMSC} = Emission factor for MMS component, as specified in Table JJ–7 of this section (kg N_2O-N/kg N).

$$N_{ex\,AT} = Population_{AT} \times TAM_{AT} \times N_{AT}/1000 \qquad \text{(Eq. JJ-14)}$$

Where:

$N_{ex\,AT}$ = Total nitrogen excreted per animal type (kg/day).

$Population_{AT}$ = Average annual animal population contributing manure to the manure management system by animal type (head) (see description in § 98.363(a)(i) and (ii)).

TAM_{AT} = Typical animal mass by animal type, using either default values in Table JJ–2 of this section or farm-specific data (kg/head).

N_{AT} = Nitrogen excretion rate by animal type, using default values in Tables JJ–2 or JJ–3 of this section (kg N/day/1000 kg animal mass).

(d) Estimate the annual total facility emissions using Equation JJ–15 of this section.

$$\text{Total Emissions (metric tons } CO_2e/yr) = \left[\left(CH_4\ emissions_{MMS} + CH_4\ emissions_{AD}\right) \text{ x } 21\right] + [\text{Direct } N_2O \text{ emissions x } 310] \qquad \text{(Eq. JJ-15)}$$

Where:

$CH_4\ emissions_{MMS}$ = From Equation JJ–2 of this section.

$CH_4\ emissions_{AD}$ = From Equation JJ–5 of this section.

21 = Global Warming Potential of CH_4.

Direct N_2O emissions = From Equation JJ–13 of this section.

310 = Global Warming Potential of N_2O.

§ 98.364 Monitoring and QA/QC requirements.

(a) Perform an annual animal inventory or review of facility records (for static populations) or population calculation (for growing populations) to determine the average annual animal population for each animal type (see description in § 98.363(a)(1) and (2)).

(b) Perform an analysis on your operation to determine the fraction of total manure by weight for each animal type that is managed in each on-site manure management system component. If your system changes from previous reporting periods, you must reevaluate the fraction of total manure managed in each system component.

(c) The CH_4 concentration of gas from digesters must be determined using ASTM D1946–90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference *see* § 98.7). All gas composition monitors shall be calibrated prior to the first reporting year for biogas methane and carbon dioxide content using ASTM D1946–90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference *see* § 98.7)and recalibrated either annually or at the minimum frequency specified by the manufacturer, whichever is more frequent, or whenever the error in the midrange calibration check exceeds ± 10 percent. All monitors shall be maintained as specified by the manufacturer.

(d) All temperature and pressure monitors must be calibrated using the procedures and frequencies specified by the manufacturer. All equipment (temperature and pressure monitors) shall be maintained as specified by the manufacturer.

(e) For digesters with gas collection systems, install, operate, maintain, and calibrate a gas flow meter capable of measuring the volumetric flow rate to provide data for the GHG emissions calculations, using the applicable methods specified in paragraphs (e)(1) through (e)(6) of this section or as specified by the manufacturer.

(1) ASME MFC–3M–2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, *see* § 98.7).

(2) ASME MFC–4M–1986 (Reaffirmed 1997) Measurement of Gas Flow by Turbine Meters (incorporated by reference, *see* § 98.7).

(3) ASME MFC–6M–1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, *see* § 98.7).

(4) ASME MFC–7M–1987 (Reaffirmed 1992) Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, *see* § 98.7).

(5) ASME MFC–14M–2003 Measurement of Fluid Flow Using Small Bore Precision Orifice Meters (incorporated by reference, *see* § 98.7).

(6) ASME MFC–18M–2001 Measurement of Fluid Flow using Variable Area Meters (incorporated by reference, *see* § 98.7).

(f) If applicable, the owner or operator shall document the procedures used to ensure the accuracy of gas flow rate, gas composition, temperature, and pressure measurements. These procedures include, but are not limited to, calibration of fuel flow meters and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

(g) Each gas flow meter shall be calibrated prior to the first reporting year and recalibrated either annually or at the minimum frequency specified by the manufacturer, whichever is more frequent. Each gas flow meter must have a rated accuracy of ± 5 percent or lower and be capable of correcting for the temperature and pressure and, if the gas composition monitor determines CH_4 concentration on a dry basis, moisture content.

§ 98.365 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the requirements in paragraph (b) of this section.

(b) For missing gas flow rates or CH_4 content data, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

§ 98.366 Data reporting requirements.

(a) In addition to the information required by § 98.3(c), each annual report must contain the following information:

(1) List of manure management system components at the facility.

(2) Fraction of manure from each animal type that is handled in each manure management system component.

(3) Average annual animal population (for each animal type) for static populations or the results of Equation JJ–4 for growing populations.

(4) Average number of days that growing animals are kept at the facility (for each animal type).

(5) The number of animals produced annually for growing populations (for each animal type).

(6) Typical animal mass (for each animal type).

(7) Total facility emissions (results of Equation JJ–15).

(8) CH_4 emissions from manure management system components listed in § 98.360(b), except digesters (results of Equation JJ–2).

(9) VS value used (for each animal type).

(10) B_0 value used (for each animal type).

(11) Methane conversion factor used for each MMS component.

(12) Average ambient temperature used to select each methane conversion factor.

(13) N_2O emissions (results of Equation JJ–13).

(14) N value used for each animal type.

(15) N_2O emission factor selected for each MMS component.

(b) Facilities with anaerobic digesters must also report:

(1) CH_4 emissions from anaerobic digesters (results of Equation JJ–5).

(2) CH_4 flow to the digester combustion device for each digester (results of Equation JJ–6, or value from fully integrated monitoring system as described in 98.363(b)).

(3) CH_4 destruction for each digester (results of Equation JJ–11).

(4) CH_4 leakage for each digester (results of Equation JJ–12).

(5) Total annual volumetric biogas flow for each digester (results of Equation JJ–7).

(6) Average annual CH_4 concentration for each digester (results of Equation JJ–8).

(7) Average annual temperature at which gas flow is measured for each digester (results of Equation JJ–9).

(8) Average annual gas flow pressure at which gas flow is measured for each digester (results of Equation JJ–10).

(9) Destruction efficiency used for each digester.

(10) Number of days per year that each digester was operating.

(11) Collection efficiency used for each digester.

§ 98.367 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the calibration records for all monitoring equipment, including the method or manufacturer's specification used for calibration.

§ 98.368 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE JJ–1 TO SUBPART JJ OF PART 98—ANIMAL POPULATION THRESHOLD LEVEL BELOW WHICH FACILITIES ARE NOT REQUIRED TO REPORT EMISSIONS UNDER SUBPART JJ [1,2]

Animal group	Average annual animal population (Head) [3]
Beef	29,300
Dairy	3,200
Swine	34,100
Poultry:	
Layers	723,600
Broilers	38,160,000
Turkeys	7,710,000

[1] The threshold head populations in this table were calculated using the most conservative assumptions (high VS and N values, maximum ambient temperatures, and the application of an uncertainty factor) to ensure that facilities at or near the 25,000 metric ton CO_2e threshold level were not excluded from reporting.

[2] For facilities with more than one animal group present refer to § 98.360 (2) to estimate the combined animal group factor (CAGF), which is used to determine if a facility may be required to report.

[3] For all animal groups except dairy, the average annual animal population represents the total number of animals present at the facility. For dairy facilities, the average annual animal population represents the number of mature dairy cows present at the facility (note that heifers and calves were included in the emission estimates for dairy facilities using the assumption that the average annual animal population of heifers and calves at dairy facilities are equal to 30 percent of the mature dairy cow average annual animal population, therefore the average annual population for dairy facilities should not include heifers and calves, only dairy cows).

TABLE JJ–2 TO SUBPART JJ OF PART 98—WASTE CHARACTERISTICS DATA

Animal type	Typical animal mass (kg)	Volatile solids excretion rate (kg VS/day/1000 kg animal mass)	Nitrogen excretion rate (kg N/day/1000 kg animal mass)	Maximum methane generation potential, B_o (m^3 CH_4/kg VS added)
Dairy Cows	604	See Table JJ–3	See Table JJ–3	0.24
Dairy Heifers	476	See Table JJ–3	See Table JJ–3	0.17
Dairy Calves	118	6.41	0.30	0.17
Feedlot Steers	420	See Table JJ–3	See Table JJ–3	0.33
Feedlot heifers	420	See Table JJ–3	See Table JJ–3	0.33
Market Swine <60 lbs	16	8.80	0.60	0.48
Market Swine 60–119 lbs	41	5.40	0.42	0.48
Market Swine 120–179 lbs	68	5.40	0.42	0.48
Market Swine >180 lbs	91	5.40	0.42	0.48
Breeding Swine	198	2.60	0.24	0.48

TABLE JJ–2 TO SUBPART JJ OF PART 98—WASTE CHARACTERISTICS DATA—Continued

Animal type	Typical animal mass (kg)	Volatile solids excretion rate (kg VS/day/1000 kg animal mass)	Nitrogen excretion rate (kg N/day/1000 kg animal mass)	Maximum methane generation potential, B_o (m^3 CH_4/kg VS added)
Feedlot Sheep	25	9.20	0.42	0.36
Goats	64	9.50	0.45	0.17
Horses	450	10.00	0.30	0.33
Hens >/= 1 yr	1.8	10.09	0.83	0.39
Pullets	1.8	10.09	0.62	0.39
Other Chickens	1.8	10.80	0.83	0.39
Broilers	0.9	15.00	1.10	0.36
Turkeys	6.8	9.70	0.74	0.36

TABLE JJ–3 TO SUBPART JJ OF PART 98—STATE-SPECIFIC VOLATILE SOLIDS (VS) AND NITROGEN (N) EXCRETION RATES FOR CATTLE

State	Volatile solids excretion rate (kg VS/day/1000 kg animal mass)				Nitrogen excretion rate (kg VS/day/1000 kg animal mass)			
	Dairy cows	Dairy heifers	Feedlot steer	Feedlot heifers	Dairy cows	Dairy heifers	Feedlot steer	Feedlot heifers
Alabama	8.40	8.35	4.27	4.74	0.50	0.46	0.36	0.38
Alaska	7.30	8.35	4.15	4.58	0.45	0.46	0.35	0.37
Arizona	10.37	8.35	3.91	4.27	0.58	0.46	0.33	0.34
Arkansas	7.59	8.35	3.98	4.35	0.46	0.46	0.33	0.35
California	10.02	8.35	3.96	4.33	0.56	0.46	0.33	0.34
Colorado	10.25	8.35	3.97	4.34	0.58	0.46	0.33	0.35
Connecticut	9.22	8.35	4.41	4.93	0.53	0.46	0.37	0.40
Delaware	8.63	8.35	4.19	4.64	0.51	0.46	0.35	0.37
Florida	8.90	8.35	4.15	4.58	0.52	0.46	0.35	0.37
Georgia	9.07	8.35	4.18	4.63	0.53	0.46	0.35	0.37
Hawaii	7.00	8.35	4.15	4.58	0.44	0.46	0.35	0.37
Idaho	10.11	8.35	4.03	4.42	0.57	0.46	0.34	0.35
Illinois	9.07	8.35	4.15	4.59	0.52	0.46	0.35	0.37
Indiana	9.38	8.35	3.98	4.35	0.54	0.46	0.33	0.35
Iowa	9.46	8.35	3.93	4.28	0.54	0.46	0.33	0.34
Kansas	9.63	8.35	3.97	4.35	0.55	0.46	0.33	0.35
Kentucky	7.89	8.35	4.20	4.65	0.48	0.46	0.35	0.37
Louisiana	7.39	8.35	4.07	4.48	0.45	0.46	0.34	0.36
Maine	8.99	8.35	4.07	4.47	0.52	0.46	0.34	0.36
Maryland	9.02	8.35	4.05	4.45	0.52	0.46	0.34	0.35
Massachusetts	8.63	8.35	4.15	4.58	0.51	0.46	0.35	0.37
Michigan	10.05	8.35	4.00	4.38	0.57	0.46	0.34	0.35
Minnesota	9.17	8.35	3.89	4.24	0.53	0.46	0.33	0.34
Mississippi	8.19	8.35	4.14	4.57	0.49	0.46	0.35	0.37
Missouri	8.02	8.35	4.08	4.49	0.48	0.46	0.34	0.36
Montana	9.03	8.35	4.23	4.69	0.52	0.46	0.36	0.38
Nebraska	9.09	8.35	3.98	4.35	0.53	0.46	0.33	0.35
Nevada	9.65	8.35	4.07	4.48	0.55	0.46	0.34	0.36
New Hampshire	9.44	8.35	3.94	4.30	0.54	0.46	0.33	0.34
New Jersey	8.51	8.35	3.98	4.36	0.50	0.46	0.33	0.35
New Mexico	10.34	8.35	3.88	4.22	0.58	0.46	0.32	0.33
New York	9.42	8.35	3.75	4.05	0.54	0.46	0.31	0.32
North Carolina	9.38	8.35	4.20	4.65	0.55	0.46	0.35	0.37
North Dakota	8.40	8.35	3.88	4.22	0.50	0.46	0.32	0.34
Ohio	9.01	8.35	3.96	4.33	0.52	0.46	0.33	0.34
Oklahoma	8.58	8.35	3.98	4.35	0.50	0.46	0.33	0.35
Oregon	9.40	8.35	4.06	4.46	0.54	0.46	0.34	0.36
Pennsylvania	9.26	8.35	3.98	4.35	0.53	0.46	0.33	0.35
Rhode Island	8.94	8.35	4.36	4.87	0.52	0.46	0.37	0.39
South Carolina	9.05	8.35	4.15	4.58	0.53	0.46	0.35	0.37
South Dakota	9.45	8.35	4.01	4.39	0.54	0.46	0.34	0.35
Tennessee	8.60	8.35	4.48	5.02	0.51	0.46	0.38	0.40
Texas	9.51	8.35	3.95	4.32	0.54	0.46	0.33	0.34
Utah	9.70	8.35	3.88	4.22	0.55	0.46	0.32	0.34
Vermont	9.03	8.35	4.10	4.52	0.52	0.46	0.34	0.36
Virginia	9.02	8.35	3.98	4.35	0.53	0.46	0.33	0.35
Washington	10.36	8.35	4.07	4.47	0.58	0.46	0.34	0.36
West Virginia	8.13	8.35	4.65	5.25	0.48	0.46	0.40	0.42
Wisconsin	9.34	8.35	3.95	4.31	0.54	0.46	0.33	0.34

TABLE JJ–3 TO SUBPART JJ OF PART 98—STATE-SPECIFIC VOLATILE SOLIDS (VS) AND NITROGEN (N) EXCRETION RATES FOR CATTLE—Continued

State	Volatile solids excretion rate (kg VS/day/1000 kg animal mass)				Nitrogen excretion rate (kg VS/day/1000 kg animal mass)			
	Dairy cows	Dairy heifers	Feedlot steer	Feedlot heifers	Dairy cows	Dairy heifers	Feedlot steer	Feedlot heifers
Wyoming	9.29	8.35	4.17	4.61	0.53	0.46	0.35	0.37

TABLE JJ–4 TO SUBPART JJ OF PART 98—VOLATILE SOLIDS AND NITROGEN REMOVAL THROUGH SOLIDS SEPARATION

Type of solids separation	Volatile solids removal (decimal)	Nitrogen removal (decimal)
Gravity	0.60	0.60
Mechanical:		
Stationary Screen	0.20	0.10
Vibrating Screen	0.15	0.15
Screw Press	0.25	0.15
Centrifuge	0.50	0.25
Roller drum	0.25	0.15
Belt press/screen	0.50	0.30

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Table JJ-5 to Subpart JJ of Part 98—Methane Conversion Factors

Manure Management System Component	MCFs by Average Annual Ambient Temperature (degrees C)																		
	Cool					Temperate											Warm		
	<10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	>28
Uncovered Anaerobic Lagoon	66%	68%	70%	71%	73%	74%	75%	76%	77%	77%	78%	78%	78%	79%	79%	79%	79%	80%	80%
Liquid/slurry (with crust cover)	10%	11%	13%	14%	15%	17%	18%	20%	22%	24%	26%	29%	31%	34%	37%	41%	44%	48%	50%
Liquid/slurry (w/o crust cover)	17%	19%	20%	22%	25%	27%	29%	32%	35%	39%	42%	46%	50%	55%	60%	65%	71%	78%	80%
Storage pits <1 month	3.0%					3.0%											30.0%		
Storage pits >1 month	17%	19%	20%	22%	25%	27%	29%	32%	35%	39%	42%	46%	50%	55%	60%	65%	71%	78%	80%
Solid manure storage	2.0%					4.0%											5.0%		
Dry lots (including feedlots)	1.0%					1.5%											2.0%		
High-rise houses for poultry production (without litter)	1.5%					1.5%											1.5%		
Poultry production with litter	1.5%					1.5%											1.5%		
Deep bedding systems for cattle and swine (<1 month)	3.0%					3.0%											30.0%		
Deep bedding systems for cattle and swine (>1 month)	17%	19%	20%	22%	25%	27%	29%	32%	35%	39%	42%	46%	50%	55%	60%	65%	71%	78%	80%
Manure Composting - In Vessel	0.5%					0.5%											0.5%		
Manure Composting - Static Pile	0.5%					0.5%											0.5%		
Manure Composting-Extensive/Passive	0.5%					1.0%											1.5%		
Manure Composting-Intensive	0.5%					1.0%											1.5%		
Aerobic Treatment	0.0%					0.0%											0.0%		

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TABLE JJ–6 TO SUBPART JJ OF PART 98—COLLECTION EFFICIENCIES OF ANAEROBIC DIGESTERS

Anaerobic digester type	Cover type	Methane collection efficiency
Covered anaerobic lagoon (biogas capture)	Bank to bank, impermeable	0.975
	Modular, impermeable	0.70
Complete mix, fixed film, or plug flow digester	Enclosed Vessel	0.99

TABLE JJ–7 TO SUBPART JJ OF PART 98—NITROUS OXIDE EMISSION FACTORS (KG N_2O–N/KG KJDL N)

Manure management system component	N_2O emission factor
Uncovered anaerobic lagoon	0
Liquid/Slurry (with crust cover)	0.005
Liquid/Slurry (without crust cover)	0
Storage pits	0.002
Digesters	0
Solid manure storage	0.005
Dry lots (including feedlots)	0.02
High-rise house for poultry (poultry without litter)	0.001
Poultry production with litter	0.001
Deep bedding for cattle and swine (active mix)	0.07
Deep bedding for cattle and swine (no mix)	0.01
Manure Composting (in vessel)	0.006
Manure Composting (intensive)	0.1
Manure Composting (passive)	0.01
Manure Composting (static)	0.006
Aerobic Treatment (forced aeration)	0.005
Aerobic Treatment (natural aeration)	0.01

Subpart KK—[Reserved]

Subpart LL—Suppliers of Coal-based Liquid Fuels

§ 98.380 Definition of the source category.

This source category consists of producers, importers, and exporters of products listed in Table MM–1 of subpart MM that are coal-based (coal-to-liquid products).

(a) A producer is the owner or operator of a coal-to-liquids facility. A coal-to-liquids facility is any facility engaged in converting coal into liquid products using a process involving conversion of coal into gas and then into liquids (e.g., Fischer-Tropsch) or conversion of coal directly into liquids (i.e., direct liquefaction).

(b) An importer or exporter shall have the same meaning given in § 98.6.

§ 98.381 Reporting threshold.

Any supplier of coal-to-liquid products who meets the requirements of § 98.2(a)(4) must report GHG emissions.

§ 98.382 GHGs to report.

You must report the CO_2 emissions that would result from the complete combustion or oxidation of fossil-fuel products (besides coal or crude oil) that you produce, use as feedstock, import, or export during the calendar year. Additionally, producers must report CO_2 emissions that would result from the complete combustion or oxidation of any biomass co-processed with fossil fuel-based feedstocks.

§ 98.383 Calculating GHG emissions.

You must follow the calculation methodologies of § 98.393 as if they applied to the appropriate coal-to-liquid product supplier (i.e., calculation methodologies for refiners apply to producers of coal-to-liquid products and calculation methodologies for importers and exporters of petroleum products apply to importers and exporters of coal-to-liquid products).

(a) In calculation methodologies in § 98.393 for petroleum products or petroleum-based products, suppliers of coal-to-liquid products shall also include coal-to-liquid products.

(b) In calculation methodologies in § 98.393 for non-crude feedstocks or non-crude petroleum feedstocks, producers of coal-to-liquid products shall also include coal-to-liquid products that enter the facility to be further processed or otherwise used on site.

(c) In calculation methodologies in § 98.393 for petroleum feedstocks, suppliers of coal-to-liquid products shall also include coal and coal-to-liquid products that enter the facility to be further processed or otherwise used on site.

§ 98.384 Monitoring and QA/QC requirements.

You must follow the monitoring and QA/QC requirements in § 98.394 as if they applied to the appropriate coal-to-liquid product supplier. Any monitoring and QA/QC requirement for petroleum products in § 98.394 also applies to coal-to-liquid products.

§ 98.385 Procedures for estimating missing data.

You must follow the procedures for estimating missing data in § 98.395 as if they applied to the appropriate coal-to-liquid product supplier. Any procedure for estimating missing data for petroleum products in § 98.395 also applies to coal-to-liquid products.

§ 98.386 Data reporting requirements.

In addition to the information required by § 98.3(c), the following requirements apply:

(a) Producers shall report the following information for each coal-to-liquid facility:

(1) For each product listed in Table MM–1 of subpart MM of this part that enters the coal-to-liquid facility to be further processed or otherwise used on site, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

(2) For each product listed in Table MM–1 of subpart MM of this part that enters the coal-to-liquid facility to be further processed or otherwise used on site, report the total annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(3) For each feedstock reported in paragraph (a)(2) that was produced by blending a fossil fuel-based product with a biomass-based product, report the percent of the volume reported in paragraph (a)(2) of this section that is fossil fuel-based.

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(1) of this section.

(5) For each product (leaving the coal-to-liquid facility) listed in Table MM–1 of subpart MM of this part, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

(6) For each product (leaving the coal-to-liquid facility) listed in Table MM–1 of subpart MM of this part, report the total annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(7) For each product reported in paragraph (a)(6) of this section that was produced by blending a fossil fuel-based

product with a biomass-based product, report the percent of the volume reported in paragraph (a)(6) of this section that is fossil fuel-based.

(8) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(5) of this section.

(9) For every feedstock reported in paragraph (a)(2) of this section for which Calculation Methodology 2 of subpart MM of this part was used to determine an emissions factor, report:

(i) The number of samples collected according to § 98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO_2 emissions factor.

(10) For every non-solid feedstock reported in paragraph (a)(2) of this section for which Calculation Methodology 2 of subpart MM of this part was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(11) For every product reported in paragraph (a)(6) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The number of samples collected according to § 98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO_2 emissions factor.

(12) For every non-solid product reported in paragraph (a)(6) of this section for which Calculation Methodology 2 of subpart MM of this part was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(13) For each specific type of biomass that enters the coal-to-liquid facility to be co-processed with fossil fuel-based feedstock to produce a product reported in paragraph (a)(6) of this section, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used.

(14) For each specific type of biomass that enters the coal-to-liquid facility to be co-processed with fossil fuel-based feedstock to produce a product reported in paragraph (a)(6) of this section, report the total annual quantity in metric tons or barrels.

(15) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(3) of this section.

(16) The CO_2 emissions in metric tons that would result from the complete combustion or oxidation of each feedstock reported in paragraph (a)(2) of this section, calculated according to § 98.393(b) or (h).

(17) The CO_2 emissions in metric tons that would result from the complete combustion or oxidation of each product (leaving the coal-to-liquid facility) reported in paragraph (a)(6) of this section, calculated according to § 98.393(a) or (h).

(18) Annual CO_2 emissions in metric tons that would result from the complete combustion or oxidation of each type of biomass feedstock co-processed with fossil fuel-based feedstocks reported in paragraph (a)(3) of this section, calculated according to § 98.393(c).

(19) Annual CO_2 emissions that would result from the complete combustion or oxidation of all products, calculated according to § 98.393(d).

(20) Annual quantity of bulk NGLs in metric tons or barrels received for processing during the reporting year.

(b) In addition to the information required by § 98.3(c), each importer shall report all of the following information at the corporate level:

(1) For each product listed in Table MM–1 of subpart MM of this part, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

(2) For each product listed in Table MM–1 of subpart MM of this part, report the total annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product as listed in Table MM–1 of subpart MM of this part.

(3) For each product reported in paragraph (b)(2) of this section that was produced by blending a fossil fuel-based product with a biomass-based product, report the percent of the volume reported in paragraph (b)(2) of this section that is fossil fuel-based.

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (b)(1) of this section.

(5) For each product reported in paragraph (b)(2) of this section for which Calculation Methodology 2 of this subpart used was used to determine an emissions factor, report:

(i) The number of samples collected according to § 98.394(c)

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO_2 emissions factor in metric tons.

(6) For each non-solid product reported in paragraph (b)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The density test results in metric tons ber barrel.

(ii) The standard method used to test density.

(7) The CO_2 emissions in metric tons that would result from the complete combustion or oxidation of each imported product reported in paragraph (b)(2) of this section, calculated according to § 98.393(a).

(8) The total sum of CO_2 emissions that would result from the complete combustion or oxidation of all imported products, calculated according to § 98.393(e).

(c) In addition to the information required by § 98.3(c), each exporter shall report all of the following information at the corporate level:

(1) For each product listed in Table MM–1 of subpart MM of this part, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

(2) For each product listed in table MM–1 of subpart MM of this part, report the total annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(3) For each product reported in paragraph (c)(2) of this section that was produced by blending a fossil fuel-based product with a biomass-based product, report the percent of the volume reported in paragraph (c)(2) of this section that is fossil fuel-based.

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (c)(1) of this section.

(5) For each product reported in paragraph (c)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The number of samples collected according to § 98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO_2 emissions factor in metric tons.

(6) For each non-solid product reported in paragraph (c)(2) of this section for which Calculation Methodology 2 of this subpart used was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(7) The CO_2 emissions in metric tons that would result from the complete combustion or oxidation of each exported product reported in paragraph (c)(2) of this section, calculated according to § 98.393(a).

(8) Total sum of CO_2 emissions that would result from the complete combustion or oxidation of all exported products, calculated according to § 98.393(e).

§ 98.387 Records that must be retained.

You must retain records according to the requirements in § 98.397 as if they applied to the appropriate coal-to-liquid product supplier (e.g., retaining copies of all reports submitted to EPA under § 98.386 and records to support information contained in those reports). Any records for petroleum products that are required to be retained in § 98.397 are also required for coal-to-liquid products.

§ 98.388 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart MM—Suppliers of Petroleum Products

§ 98.390 Definition of the source category.

This source category consists of petroleum refineries and importers and exporters of petroleum products and natural gas liquids as listed in Table MM–1 of this subpart.

(a) A petroleum refinery for the purpose of this subpart is any facility engaged in producing petroleum products through the distillation of crude oil.

(b) A refiner is the owner or operator of a petroleum refinery.

(c) Importer has the same meaning given in § 98.6 and includes any entity that imports petroleum products or natural gas liquids as listed in Table MM–1 of this subpart. Any blender or refiner of refined or semi-refined petroleum products shall be considered an importer if it otherwise satisfies the aforementioned definition.

(d) Exporter has the same meaning given in § 98.6 and includes any entity that exports petroleum products or natural gas liquids as listed in Table MM–1 of this subpart. Any blender or refiner of refined or semi-refined petroleum products shall be considered an exporter if it otherwise satisfies the aforementioned definition.

§ 98.391 Reporting threshold.

Any supplier of petroleum products who meets the requirements of § 98.2(a)(4) must report GHG emissions.

§ 98.392 GHGs To report.

Suppliers of petroleum products must report the CO_2 emissions that would result from the complete combustion or oxidation of each petroleum product and natural gas liquid produced, used as feedstock, imported, or exported during the calendar year. Additionally, refiners must report CO_2 emissions that would result from the complete combustion or oxidation of any biomass co-processed with petroleum feedstocks.

§ 98.393 Calculating GHG emissions.

(a) Calculation for individual products produced, imported, or exported.

(1) Except as provided in paragraph (h) of this section, any refiner, importer, or exporter shall calculate CO_2 emissions from each individual petroleum product and natural gas liquid using Equation MM–1 of this section.

$$CO_{2i} = Product_i \star EF_i \qquad \text{(Eq. MM-1)}$$

Where:

CO_{2i} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each petroleum product or natural gas liquid ''i'' (metric tons).

$Product_i$ = Annual volume of product ''i'' produced, imported, or exported by the reporting party (barrels). For refiners, this volume only includes products ex refinery gate. For natural gas liquids, volumes shall reflect the individual components of the product as listed in Table MM–1 of this subpart.

EF_i = Product-specific CO_2 emission factor (metric tons CO_2 per barrel).

(2) In the event that an individual petroleum product is produced as a solid rather than liquid any refiner, importer, or exporter shall calculate CO_2 emissions using Equation MM–1 of this section.

Where:

CO_{2i} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each petroleum product ''i'' (metric tons).

$Product_i$ = Annual mass of product ''i'' produced, imported, or exported by the reporting party (metric tons). For refiners, this mass only includes products ex refinery gate.

EF_i = Product-specific CO_2 emission factor (metric tons CO_2 per metric ton of product).

(b) Calculation for individual products that enter a refinery as a non-crude feedstock.

(1) Except as provided in paragraph (h) of this section, any refiner shall calculate CO_2 emissions from each non-crude feedstock using Equation MM–2 of this section.

$$CO_{2j} = Feedstock_j \star EF_j \qquad \text{(Eq. MM-2)}$$

Where:

CO_{2j} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each non-crude feedstock ''j'' (metric tons).

$Feedstock_j$ = Annual volume of a petroleum product or natural gas liquid ''j'' that enters the refinery to be further refined or otherwise used on site (barrels). For natural gas liquids, volumes shall reflect the individual components of the product as listed in table MM–1 of this subpart.

EF_j = Feedstock-specific CO_2 emission factor (metric tons CO_2 per barrel).

(2) In the event that a non-crude feedstock enters a refinery as a solid rather than liquid, the refiner shall calculate CO_2 emissions using Equation MM–2 of this section.

Where:

CO_{2j} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each non-crude feedstock ''j'' (metric tons).

$Feedstock_j$ = Annual mass of a petroleum product ''j'' that enters the refinery to be further refined or otherwise used on site (metric tons).

EF_j = Feedstock-specific CO_2 emission factor (metric tons CO_2 per metric ton of feedstock).

(c) Calculation for biomass co-processed with petroleum feedstocks.

(1) Refiners shall calculate CO_2 emissions from each type of biomass that enters a refinery and is co-processed with petroleum feedstocks using Equation MM–3 of this section.

$$CO_{2m} = Biomass_m \star EF_m \qquad \text{(Eq. MM-3)}$$

Where:

CO_{2m} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each type of biomass ''m'' (metric tons).

$Biomass_m$ = Annual volume of a specific type of biomass that enters the refinery and is co-processed with petroleum feedstocks to produce a petroleum product reported under paragraph (a) of this section (barrels).

EF_m = Biomass-specific CO_2 emission factor (metric tons CO_2 per barrel).

(2) In the event that biomass enters a refinery as a solid rather than liquid and is co-processed with petroleum feedstocks, the refiner shall calculate CO_2 emissions from each type of biomass using Equation MM–3 of this section.

Where:

CO_{2m} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each type of biomass ''m'' (metric tons).

$Biomass_m$ = Total annual mass of a specific type of biomass that enters the refinery to be co-processed with petroleum feedstocks to produce a petroleum product reported under paragraph (a) of this section (metric tons).

EF_m = Biomass-specific CO_2 emission factor (metric tons CO_2 per metric ton of biomass).

(d) *Summary calculation for refinery products.* Refiners shall calculate annual CO_2 emissions from all products using Equation MM–4 of this section.

$$CO_{2r} = \sum(CO_{2i}) - \sum(CO_{2j}) - \sum(CO_{2m}) \qquad \text{(Eq. MM-4)}$$

Where:

CO_{2r} = Annual CO_2 emissions that would result from the complete combustion or oxidation of all petroleum products and natural gas liquids (ex refinery gate) minus non-crude feedstocks and any biomass to be co-processed with petroleum feedstocks.

CO_{2i} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each petroleum product or natural gas liquid ''i'' (metric tons).

CO_{2j} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each non-crude feedstock ''j'' (metric tons).

CO_{2m} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each type of biomass ''m'' (metric tons).

(e) *Summary calculation for importer and exporter products.* Importers and exporters shall calculate annual CO_2 emissions from all petroleum products and natural gas liquids imported or exported, respectively, using Equations MM–1 and MM–5 of this section.

$$CO_{2x} = \sum(CO_{2i}) \qquad \text{(Eq. MM-5)}$$

Where:

CO_{2i} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each petroleum product or natural gas liquid ''i'' (metric tons).

CO_{2x} = Annual CO_2 emissions that would result from the complete combustion or oxidation of all petroleum products and natural gas liquids.

(f) *Emission factors for petroleum products and natural gas liquids.* The emission factor ($EF_{i,j}$) for each petroleum product and natural gas liquid shall be determined using either of the calculation methods described in paragraphs (f)(1) or (f)(2) of this section. The same calculation method must be used for the entire quantity of the product for the reporting year. For refiners, the quantity of a product that enters a refinery (i.e., a non-crude feedstock) is considered separate from the quantity of a product ex refinery gate.

(1) *Calculation Method 1.* For solid products, use the default carbon share factor (i.e., percent carbon by mass) in column B of Table MM–1 of this subpart for the appropriate product. For all other products, use the default CO_2 emission factor listed in column C of Table MM–1 of this subpart for the appropriate product.

(2) Calculation Method 2.

(i) For solid products, develop emission factors according to Equation MM–6 of this section using a value of 1 for density and direct measurements of carbon share according to methods set forth in § 98.394(c). For all other products, develop emission factors according to Equation MM–6 of this section using direct measurements of density and carbon share according to methods set forth in § 98.394(c).

$$EF_{i,j} = \text{Density} \star \text{Carbon Share} \star (44/12) \qquad \text{(Eq. MM-6)}$$

Where:

$EF_{i,j}$ = Emission factor of the petroleum product or natural gas liquid (metric tons CO_2 per barrel or per metric ton of product).

Density = Density of the petroleum product or natural gas liquid (metric tons per barrel for non-solid products, 1 for solid products).

Carbon share = Percent of total mass that carbon represents in the petroleum product or natural gas liquid, expressed as a fraction (e.g., 75% would be expressed as 0.75 in the above equation).

44/12 = Conversion factor for carbon to carbon dioxide.

(ii) If you use a standard method that involves gas chromatography to determine the percent mass of each component in a product, calculate the product's carbon share using Equation MM–7 of this section.

$$\text{Carbon Share} = \sum(\%\text{Composition}_{i...n} \star \%\text{Mass}_{i...n}) \qquad \text{(Eq. MM-7)}$$

Where:

Carbon Share = Percent of total mass that carbon represents in the petroleum product or natural gas liquid.

%Composition i* * *n = Percent of total mass that each molecular component in the petroleum product or natural gas liquid represents as determined by the procedures in the selected standard method.

$\%Mass_{i*\,*\,*n}$ = Percent of total mass that carbon represents in each molecular component of the petroleum product or natural gas liquid.

(g) *Emission factors for biomass co-processed with petroleum feedstocks.* Refiners shall use the most appropriate default CO_2 emission factor (EF_m) for biomass in Table MM–2 of this subpart to calculate CO_2 emissions in paragraph (c) of this section.

(h) *Special procedures for blended biomass-based fuels.* In the event that some portion of a petroleum product is biomass-based and was not derived by co-processing biomass and petroleum feedstocks together (i.e., the petroleum product was produced by blending a petroleum-based product with a biomass-based fuel), the reporting party shall calculate emissions for the petroleum product according to one of the methods in paragraphs (h)(1) through (h)(4) of this section, as appropriate.

(1) A reporter using Calculation Methodology 1 to determine the emission factor of a petroleum product shall calculate the CO_2 emissions associated with that product using Equation MM–8 of this section in place of Equation MM–1 of this section.

$$CO_{2i} = Product_i \star EF_i \star \%Vol_i \qquad \text{(Eq. MM-8)}$$

Where:

CO_{2i} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each petroleum product ''i'' (metric tons).

$Product_i$ = Annual volume of each petroleum product ''i'' produced, imported, or exported by the reporting party (barrels). For refiners, this volume only includes products ex refinery gate.

EF_i = Petroleum product-specific CO_2 emission factor (metric tons CO_2 per barrel) from Table MM–1 of this subpart.

$\%Vol_i$ = Percent volume of product ''i'' that is petroleum-based, including 2.5% of the volume of any ethanol product blended into a petroleum-based product to represent the denaturant in that ethanol product, expressed as a fraction (e.g., 75% would be expressed as 0.75 in the above equation).

(2) A refinery using Calculation Methodology 1 of this subpart to determine the emission factor of a non-crude petroleum feedstock shall calculate the CO_2 emissions associated with that feedstock using Equation MM–9 of this section in place of Equation MM–2 of this section.

$$CO_{2j} = Feedstock_j \star EF_i \star \%Vol_j \qquad \text{(Eq. MM-9)}$$

Where:

CO_{2j} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each non-crude feedstock ''j'' (metric tons).

$Feedstock_j$ = Annual volume of each petroleum product ''j'' that enters the refinery as a feedstock to be further refined or otherwise used on site (barrels).

EF_j = Non-crude petroleum feedstock-specific CO_2 emission factor (metric tons CO_2 per barrel).

$\%Vol_j$ = Percent volume of feedstock ''j'' that is petroleum-based, including 2.5% of the volume of any ethanol product blended with the petroleum-based product to represent the denaturant in that ethanol product, expressed as a fraction (e.g., 75% would be expressed as 0.75 in the above equation).

(3) A reporter using Calculation Methodology 2 of this subpart to determine the emission factor of a petroleum product must calculate the CO_2 emissions associated with that product using Equation MM–10 of this section in place of Equation MM–1 of this section.

$$CO_{2i} = \left(Product_i \star EF_i\right) - \left(Product_i \star EF_m \star \%Vol_m\right) \qquad \text{(Eq. MM-10)}$$

Where:

CO_{2i} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each product ''i'' (metric tons).

$Product_i$ = Annual volume of each petroleum product ''i'' produced, imported, or exported by the reporting party (barrels). For refiners, this volume only includes products ex refinery gate.

EF_i = Product-specific CO_2 emission factor (metric tons CO_2 per barrel).

EF_m = Default CO_2 emission factor from Table MM–2 of this subpart that most closely represents the component of product ''i'' that is biomass-based.

$\%Vol_m$ = Percent volume of petroleum product ''i'' that is biomass-based, not including 2.5% of the volume of any ethanol product blended with the petroleum-based product, which represents the denaturant in that ethanol product, expressed as a fraction (e.g., 75% would be expressed as 0.75 in the above equation).

(4) A refiner using Calculation Methodology 2 of this subpart to determine the emission factor of a non-crude petroleum feedstock must calculate the CO_2 emissions associated with that feedstock using Equation MM–11 of this section in place of Equation MM–2 of this section.

$$CO_{2j} = \left(Feedstock_j \star EF_j\right) - \left(Feedstock_i \star EF_m \star \%Vol_m\right) \qquad \text{(Eq. MM-11)}$$

Where:

CO_{2j} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each non-crude feedstock ''j'' (metric tons).

$Feedstock_j$ = Annual volume of each petroleum product ''j'' produced, imported, or exported by the reporting party that enters the refinery to be further refined or otherwise used on site (barrels).

EF_j = Feedstock-specific CO_2 emission factor (metric tons CO_2 per barrel).

EF_m = Default CO_2 emission factor from Table MM–2 of this subpart that most closely represents the component of petroleum product ''j'' that is biomass-based.

$\%Vol_m$ = Percent volume of non-crude feedstock ''j'' that is biomass-based, not including 2.5% of the volume of any ethanol product blended with the petroleum-based product, which represents the denaturant in that ethanol product, expressed as a fraction (e.g., 75% would be expressed as 0.75 in the above equation).

§ 98.394 Monitoring and QA/QC requirements.

(a) Determination of quantity.

(1) The quantity of petroleum products, natural gas liquids, biomass, and crude oil shall be determined as follows:

(i) Where an appropriate standard method published by a consensus-based standards organization exists, such a method shall be used. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(ii) Where no appropriate standard method developed by a consensus-based standards organization exists, industry standard practices shall be followed.

(iii) For products that are liquid at 60 degrees Fahrenheit and one standard atmosphere, all measurements of quantity shall be temperature-adjusted and pressure-adjusted to these conditions. For all other products, reporters shall use appropriate standard conditions specified in the standard method; if temperature and pressure conditions are not specified in the standard method or if a reporter uses an industry standard practice to determine quantity, the reporter shall use appropriate standard conditions according to established industry practices.

(2) All measurement equipment (including, but not limited to, flow meters and tank gauges) used for compliance with this subpart shall be appropriate for the standard method or industry standard practice followed under paragraph (a)(1)(i) or (a)(1)(ii) of this section.

(b) Equipment Calibration.

(1) All measurement equipment shall be calibrated prior to its first use for reporting under this subpart, using an appropriate standard method published by a consensus based standards organization or according to the equipment manufacturer's directions.

(2) Measurement equipment shall be recalibrated at the minimum frequency specified by the standard method used or by the equipment manufacturer's directions.

(c) Procedures for Calculation Methodology 2 of this subpart.

(1) Reporting parties shall collect one sample of each petroleum product or natural gas liquid on any day of each calendar month of the reporting year in which the quantity of that product was measured in accordance with the requirements of this subpart. For example, if a given product was measured as entering the refinery continuously throughout the reporting year, twelve samples of that product shall be collected over the reporting year, one on any day of each calendar month of that year. If a given product was only measured from April 15 through June 10 of the reporting year, a refiner would collect three samples during that year, one during each of the calendar months of April, May and June on a day when the product was measured as either entering or exiting the refinery. Each sample shall be collected using an appropriate standard method published by a consensus-based standards organization.

(2) Mixing and handling of samples shall be performed using an appropriate standard method published by a consensus-based standards organization.

(3) Density measurement.

(i) For all products that are not solid, reporters shall test for density using an appropriate standard method published by a consensus-based standards organization.

(ii) The density value for a given petroleum product shall be generated by either making a physical composite of all of the samples collected for the reporting year and testing that single sample or by measuring the individual samples throughout the year and defining the representative density value for the sample set by numerical means, i.e., a mathematical composite. If a physical composite is chosen as the option to obtain the density value, the reporter shall submit each of the individual samples collected during the reporting year to the laboratory responsible for generating the composite sample.

(iii) For physical composites, the reporter shall handle the individual samples and the laboratory shall mix them in accordance with an appropriate standard method published by a consensus-based standards organization.

(iv) All measurements of density shall be temperature-adjusted and pressure-adjusted to the conditions assumed for determining the quantities of the product reported under this subpart.

(4) Carbon share measurement.

(i) Reporters shall test for carbon share using an appropriate standard method published by a consensus-based standards organization.

(ii) If a standard method that involves gas chromatography is used to determine the percent mass of each component in a product, the molecular formula for each component shall be obtained from the information provided in the standard method and the atomic mass of each element in a given molecular component shall be obtained from the periodic table of the elements.

(iii) The carbon share value for a given petroleum product shall be generated by either making a physical composite of all of the samples collected for the reporting year and testing that single sample or by measuring the individual samples throughout the year and defining the representative carbon share value for the sample set by numerical means, i.e., a mathematical composite. If a physical composite is chosen as the option to obtain the carbon share value, the reporter shall submit each of the individual samples collected during the reporting year to the laboratory responsible for generating the composite sample.

(iv) For physical composites, the reporter shall handle the individual samples and the laboratory shall mix them in accordance with an appropriate standard method published by a consensus-based standards organization.

(d) Measurement of API gravity and sulfur content of crude oil.

(1) Samples of each batch of crude oil shall be taken according to an appropriate standard method published by a consensus-based standards organization.

(2) Samples shall be handled according to an appropriate standard method published by a consensus-based standards organization.

(3) API gravity shall be measured using an appropriate standard method published by a consensus-based standards organization.

(4) Sulfur content shall be measured using an appropriate standard method published by a consensus-based standards organization.

(5) All measurements shall be temperature-adjusted and pressure-adjusted to the conditions assumed for determining the quantities of crude oil reported under this subpart.

§ 98.395 Procedures for estimating missing data.

(a) *Determination of quantity.* Whenever the quality assurance procedures in § 98.394(a) cannot be followed to measure the quantity of one or more petroleum products, natural gas liquids, types of biomass, feedstocks, or crude oil batches during any period (e.g., if a meter malfunctions), the following missing data procedures shall be used:

(1) For quantities of a product that are purchased or sold, a period of missing data shall be substituted using a reporter's established procedures for billing purposes in that period as agreed to by the party selling or purchasing the product.

(2) For quantities of a product that are not purchased or sold but of which the custody is transferred, a period of missing data shall be substituted using a reporter's established procedures for tracking purposes in that period as agreed to by the party involved in custody transfer of the product.

(b) *Determination of emission factor.* Whenever any of the procedures in § 98.394(c) cannot be followed to develop an emission factor for any reason, Calculation Methodology 1 of this subpart must be used in place of Calculation Methodology 2 of this subpart for the entire reporting year.

(c) *Determination of API gravity and sulfur content of crude oil.* For missing data on sulfur content or API gravity, the substitute data value shall be the arithmetic average of the quality-assured values of API gravity or sulfur content in the batch preceding and the batch immediately following the missing data incident. If no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured values for API gravity and sulfur content obtained from the batch after the missing data period.

§ 98.396 Data reporting requirements.

In addition to the information required by § 98.3(c), the following requirements apply:

(a) Refiners shall report the following information for each facility:

(1) For each petroleum product or natural gas liquid listed in table MM–1 of this subpart that enters the refinery to be further refined or otherwise used on site, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

(2) For each petroleum product or natural gas liquid listed in Table MM–1 of this subpart that enters the refinery to be further refined or otherwise used on site, report the annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(3) For each feedstock reported in paragraph (a)(2) of this section that was produced by blending a petroleum-based product with a biomass-based product, report the percent of the volume reported in paragraph (a)(2) of this section that is petroleum-based.

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(1) of this section.

(5) For each petroleum product and natural gas liquid (ex refinery gate) listed in Table MM–1 of this subpart, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

(6) For each petroleum product and natural gas liquid (ex refinery gate) listed in Table MM–1 of this subpart, report the annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(7) For each product reported in paragraph (a)(6) of this section that was produced by blending a petroleum-based product with a biomass-based product, report the percent of the volume reported in paragraph (a)(6) of this section that is petroleum-based.

(8) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(5) of this section.

(9) For every feedstock reported in paragraph (a)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The number of samples collected according to § 98.394(c)

(ii) The sampling standard method used.

(iii) The carbon share test results in percentmass.

(iv) The standard method used to test carbon share.

(v) The calculated CO_2 emissions factor in metric tons.

(10) For every non-solid feedstock reported in paragraph (a)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(11) For every petroleum product and natural gas liquid reported in paragraph (a)(6) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The number of samples collected according to § 98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percentmass.

(iv) The standard method used to test carbon share.

(v) The calculated CO_2 emissions factor in metric tons CO_2 per barrel or per metric ton of product.

(12) For every non-solid petroleum product and natural gas liquid reported in paragraph (a)(6) for which Calculation Method 2 was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(13) For each specific type of biomass that enters the refinery to be co-processed with petroleum feedstocks to produce a petroleum product reported in paragraph (a)(6) of this section, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used.

(14) For each specific type of biomass that enters the refinery to be co-processed with petroleum feedstocks to produce a petroleum product reported in paragraph (a)(6) of this section, report the annual quantity in metric tons or barrels.

(15) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(13) of this section.

(16) The CO_2 emissions in metric tons that would result from the complete combustion or oxidation of each petroleum product and natural gas liquid (ex refinery gate) reported in paragraph (a)(6) of this section, calculated according to § 98.393(a) or (h).

(17) The CO_2 emissions in metric tons that would result from the complete combustion or oxidation of each feedstock reported in paragraph (a)(2) of this section, calculated according to § 98.393(b) or (h).

(18) The CO_2 emissions in metric tons that would result from the complete combustion or oxidation of each type of biomass feedstock co-processed with petroleum feedstocks reported in paragraph (a)(13) of this section, calculated according to § 98.393(c).

(19) The sum of CO_2 emissions that would result from the complete combustion or oxidation of all products, calculated according to § 98.393(d).

(20) All of the following information for all crude oil feedstocks used at the refinery:

(i) Batch volume in barrels.

(ii) API gravity of the batch at the point of entry at the refinery.

(iii) Sulfur content of the batch at the point of entry at the refinery.

(iv) Country of origin of the batch, if known.

(21) The quantity of bulk NGLs in metric tons or barrels received for processing during the reporting year.

(b) In addition to the information required by § 98.3(c), each importer shall report all of the following information at the corporate level:

(1) For each petroleum product and natural gas liquid listed in Table MM–1 of this subpart, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids,

quantity shall reflect the individual components of the product.

(2) For each petroleum product and natural gas liquid listed in Table MM–1 of this subpart, report the annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product as listed in Table MM–1 of this subpart.

(3) For each product reported in paragraph (b)(2) of this section that was produced by blending a petroleum-based product with a biomass-based product, report the percent of the volume reported in paragraph (b)(2) of this section that is petroleum-based.

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (b)(1) of this section.

(5) For each product reported in paragraph (b)(2) of this section for which Calculation Methodology 2 of this subpart used was used to determine an emissions factor, report:

(i) The number of samples collected according to § 98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO_2 emissions factor in metric tons CO_2 per barrel or per metric ton of product.

(6) For each non-solid product reported in paragraph (b)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(7) The CO_2 emissions in metric tons that would result from the complete combustion or oxidation of each imported petroleum product and natural gas liquid reported in paragraph (b)(2) of this section, calculated according to § 98.393(a).

(8) The sum of CO_2 emissions that would result from the complete combustion oxidation of all imported products, calculated according to § 98.393(e).

(c) In addition to the information required by § 98.3(c), each exporter shall report all of the following information at the corporate level:

(1) For each petroleum product and natural gas liquid listed in Table MM–1 of this subpart, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

(2) For each petroleum product and natural gas liquid listed in Table MM–1 of this subpart, report the annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(3) For each product reported in paragraph (c)(2) of this section that was produced by blending a petroleum-based product with a biomass-based product, report the percent of the volume reported in paragraph (c)(2) of this section that is petroleum based.

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (c)(1) of this section.

(5) For each product reported in paragraph (c)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The number of samples collected according to § 98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percentmass.

(iv) The standard method used to test carbon share.

(v) The calculated CO_2 emissions factor in metric tons CO_2 per barrel or per metric ton of product.

(6) For each non-solid product reported in paragraph (c)(2) of this section for which Calculation Methodology 2 of this subpart used was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(7) The CO_2 emissions in metric tons that would result from the complete combustion or oxidation of for each exported petroleum product and natural gas liquid reported in paragraph (c)(2) of this section, calculated according to § 98.393(a).

(8) The sum of CO_2 emissions that would result from the complete combustion or oxidation of all exported products, calculated according to § 98.393(e).

§ 98.397 Records that must be retained.

(a) All reporters shall retain copies of all reports submitted to EPA under § 98.396. In addition, all reporters shall maintain sufficient records to support information contained in those reports, including but not limited to information on the characteristics of their feedstocks and products.

(b) Reporters shall maintain records to support quantities that are reported under this subpart, including records documenting any estimations of missing data and the number of calendar days in the reporting year for which substitute data procedures were followed. For all quantities of petroleum products, natural gas liquids, biomass, and feedstocks, reporters shall maintain metering, guaging, and other records normally maintained in the course of business to document product and feedstock flows including the date of initial calibration and the frequency of recalibration for the measurement equipment used

(c) Reporters shall retain laboratory reports, calculations and worksheets used to estimate the CO_2 emissions of the quantities of petroleum products, natural gas liquids, biomass, and feedstocks reported under this subpart.

(d) Reporters shall maintain laboratory reports, calculations and worksheets used in the measurement of density and carbon share for any petroleum product or natural gas liquid for which CO_2 emissions were calculated using Calculation Methodology 2.

(e) Reporters shall maintain laboratory reports, calculations and worksheets used in the measurement of API gravity and sulfur content for every crude oil batch reported under this subpart.

(f) Estimates of missing data shall be documented and records maintained showing the calculations.

(g) Reporters described in this subpart shall also retain all records described in § 98.3(g).

§ 98.398 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE MM–1 TO SUBPART MM OF PART 98—DEFAULT FACTORS FOR PETROLEUM PRODUCTS AND NATURAL GAS LIQUIDS [1 2]

Products	Column A: density (metric tons/ bbl)	Column B: carbon share (% of mass)	Column C: emission factor (metric tons CO_2/bbl)
Finished Motor Gasoline			
Conventional—Summer			
Regular	0.1181	86.66	0.3753
Midgrade	0.1183	86.63	0.3758
Premium	0.1185	86.61	0.3763
Conventional—Winter			
Regular	0.1155	86.50	0.3663
Midgrade	0.1161	86.55	0.3684
Premium	0.1167	86.59	0.3705
Reformulated—Summer			
Regular	0.1167	86.13	0.3686
Midgrade	0.1165	86.07	0.3677
Premium	0.1164	86.00	0.3670
Reformulated—Winter			
Regular	0.1165	86.05	0.3676
Midgrade	0.1165	86.06	0.3676
Premium	0.1166	86.06	0.3679
Gasoline—Other	0.1185	86.61	0.3763
Blendstocks			
CBOB—Summer			
Regular	0.1181	86.66	0.3753
Midgrade	0.1183	86.63	0.3758
Premium	0.1185	86.61	0.3763
CBOB—Winter			
Regular	0.1155	86.50	0.3663
Midgrade	0.1161	86.55	0.3684
Premium	0.1167	86.59	0.3705
RBOB—Summer			
Regular	0.1167	86.13	0.3686
Midgrade	0.1165	86.07	0.3677
Premium	0.1164	86.00	0.3670
RBOB—Winter			
Regular	0.1165	86.05	0.3676
Midgrade	0.1165	86.06	0.3676
Premium	0.1166	86.06	0.3679
Blendstocks—Other	0.1185	86.61	0.3763
Oxygenates			
Methanol	0.1268	37.48	0.1743
GTBA	0.1257	64.82	0.2988
MTBE	0.1181	68.13	0.2950
ETBE	0.1182	70.53	0.3057
TAME	0.1229	70.53	0.3178
DIPE	0.1156	70.53	0.2990
Distillate Fuel Oil			
Distillate No. 1			
Ultra Low Sulfur	0.1346	86.40	0.4264
Low Sulfur	0.1346	86.40	0.4264
High Sulfur	0.1346	86.40	0.4264
Distillate No. 2			
Ultra Low Sulfur	0.1342	87.30	0.4296
Low Sulfur	0.1342	87.30	0.4296
High Sulfur	0.1342	87.30	0.4296
Distillate Fuel Oil No. 4	0.1452	86.47	0.4604
Residual Fuel Oil No. 5 (Navy Special)	0.1365	85.67	0.4288
Residual Fuel Oil No. 6 (a.k.a. Bunker C)	0.1528	84.67	0.4744
Kerosene-Type Jet Fuel	0.1294	86.30	0.4095
Kerosene	0.1346	86.40	0.4264
Diesel—Other	0.1452	86.47	0.4604
Petrochemical Feedstocks			

TABLE MM–1 TO SUBPART MM OF PART 98—DEFAULT FACTORS FOR PETROLEUM PRODUCTS AND NATURAL GAS LIQUIDS [1] [2]—Continued

Products	Column A: density (metric tons/bbl)	Column B: carbon share (% of mass)	Column C: emission factor (metric tons CO_2/bbl)
Naphthas (< 401 °F)	0.1158	84.11	0.3571
Other Oils (> 401 °F)	0.1390	87.30	0.4450
Unfinished Oils			
Heavy Gas Oils	0.1476	85.80	0.4643
Residuum	0.1622	85.70	0.5097
Other Petroleum Products and Natural Gas Liquids			
Aviation Gasoline	0.1120	85.00	0.3490
Special Naphthas	0.1222	84.76	0.3798
Lubricants	0.1428	85.80	0.4492
Waxes	0.1285	85.30	0.4019
Petroleum Coke	0.1818	92.28	0.6151
Asphalt and Road Oil	0.1634	83.47	0.5001
Still Gas	0.1405	77.70	0.4003
Ethane	0.0866	79.89	0.2537
Ethylene	0.0903	85.63	0.2835
Propane	0.0784	81.71	0.2349
Propylene	0.0803	85.63	0.2521
Butane	0.0911	82.66	0.2761
Butylene	0.0935	85.63	0.2936
Isobutane	0.0876	82.66	0.2655
Isobutylene	0.0936	85.63	0.2939
Pentanes Plus	0.1055	83.63	0.3235
Miscellaneous Products	0.1380	85.49	0.4326

[1] In the case of products blended with some portion of biomass-based fuel, the carbon share in Table MM–1 of this subpart represents only the petroleum-based components.

[2] Products that are derived entirely from biomass should not be reported, but products that were derived from both biomass and a petroleum product (i.e., co-processed) should be reported as the petroleum product that it most closely represents.

TABLE MM–2 TO SUBPART MM OF PART 98—DEFAULT FACTORS FOR BIOMASS-BASED FUELS AND BIOMASS

Biomass-based fuel and biomass	Column A: Density (metric tons/bbl)	Column B: Carbon share (% of mass)	Column C: Emission factor (metric tons CO_2/bbl)
Ethanol (100%)	0.1267	52.14	0.2422
Biodiesel (100%, methyl ester)	0.1396	77.30	0.3957
Rendered Animal Fat	0.1333	76.19	0.3724
Vegetable Oil	0.1460	76.77	0.4110

Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids

§ 98.400 Definition of the source category.

This supplier category consists of natural gas liquids fractionators and local natural gas distribution companies.

(a) Natural gas liquids fractionators are installations that fractionate natural gas liquids (NGLs) into their consitutent liquid products (ethane, propane, normal butane, isobutane or pentanes plus) for supply to downstream facilities.

(b) Local Distribution Companies (LDCs) are companies that own or operate distribution pipelines, not interstate pipelines or intrastate pipelines, that physically deliver natural gas to end users and that are regulated as separate operating companies by State public utility commissions or that operate as independent municipally-owned distribution systems.

(c) This supply category does not consist of the following facilities:

(1) Field gathering and boosting stations.

(2) Natural gas processing plants that separate NGLs from natural gas and produce bulk or y-grade NGLs but do not fractionate these NGLs into their constituent products.

(3) Facilities that meet the definition of refineries and report under subpart MM of this part.

(4) Facilities that meet the definition of petrochemical plants and report under subpart X of this part.

§ 98.401 Reporting threshold.

Any supplier of natural gas and natural gas liquids that meets the requirements of § 98.2(a)(4) must report GHG emissions.

§ 98.402 GHGs to report.

(a) NGL fractionators must report the CO_2 emissions that would result from the complete combustion or oxidation of the annual quantity of ethane, propane, normal butane, isobutane, and pentanes plus that is produced and sold or delivered to others.

(b) LDCs must report the CO_2 emissions that would result from the complete combustion or oxidation of the annual volumes of natural gas provided to end-users on their distribution systems.

§ 98.403 Calculating GHG emissions.

(a) LDCs and fractionators shall, for each individual product reported under this part, calculate the estimated CO_2 emissions that would result from the complete combustion or oxidation of the products supplied using either of Calculation Methodology 1 or 2 of this subpart:

(1) *Calculation Methodology 1.* NGL fractionators shall estimate CO_2 emissions that would result from the complete combustion or oxidation of the product(s) supplied using Equation NN–1 of this section. LDCs shall estimate CO_2 emissions that would result from the complete combustion or oxidation of the product received at the city gate using Equation NN–1. For each product, use the default value for higher heating value and CO_2 emission factor in Table NN–1 of this subpart. Alternatively, for each product, a reporter-specific higher heating value and CO_2 emission factor may be used, in place of one or both defaults provided they are developed using methods outlined in § 98.404. For each product, you must use the same volume unit throughout the equation.

$$CO_{2i} = 1 \times 10^{-3} \star \sum Fuel_h \star HHV_h \star EF_h \qquad \text{(Eq. NN-1)}$$

Where:

CO_{2i} = Annual CO_2 mass emissions that would result from the combustion or oxidation of each product ''h'' for redelivery to all recipients (metric tons).

Fuel = Total annual volume of product ''h'' supplied (volume per year, in Mscf for natural gas and bbl for NGLs).

HHV = Higher heating value of product ''h'' supplied (MMBtu/Mscf or MMBtu/bbl).

EF_h = CO_2 emission factor of product ''h'' (kg CO_2/MMBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons (MT/kg).

(2) *Calculation Methodology 2.* NGL fractionators shall estimate CO_2 emissions that would result from the complete combustion or oxidation of the product(s) supplied using Equation NN–2 of this section. LDCs shall estimate CO_2 emissions that would result from the complete combustion or oxidation of the product received at the city gate using Equation NN–2. For each product, use the default CO_2 emission factor found in Table NN–2 of this subpart. Alternatively, for each product, a reporter-specific CO_2 emission factor may be used in place of the default factor, provided it is developed using methods outlined in § 98.404. For each product, you must use the same volume unit throughout the equation.

$$CO_{2i} = \sum_h Fuel_h * EF_h \qquad \text{(Eq. NN-2)}$$

Where:

CO_{2i} = Annual CO_2 mass emissions that would result from the combustion or oxidation of each product ''h'' (metric tons)

Fuel = Total annual volume of product ''h'' supplied (bbl or Mscf per year)

EF_h = CO_2 emission factor of product ''h'' (MT CO_2/bbl, or MT CO_2/Mscf)

(b) Each LDC shall follow the procedures below.

(1) For natural gas that is received for redelivery to downstream gas transmission pipelines and other local distribution companies, use eEquation NN–3 of this section and the default values for the CO_2 emission factors found in Table NN–2 of this subpart. Alternatively, reporter-specific CO_2 emission factors may be used, provided they are developed using methods outlined in § 98.404.

$$CO_{2j} = Fuel \star EF \qquad \text{(Eq. NN-3)}$$

Where:

CO_{2j} = Annual CO_2 mass emissions that would result from the combustion or oxidation of natural gas for redelivery to transmission pipelines or other LDCs (metric tons).

Fuel = Total annual volume of natural gas supplied (Mscf per year).

EF = Fuel-specific CO_2 emission factor (MT CO_2/Mscf).

(2)(i) For natural gas delivered to each meter registering a supply equal to or greater than 460,000 Mscf per year, use Equation NN–4 of this section and the default values for the CO_2 emission factors found in Table NN–2 of this subpart.

(ii) Alternatively, reporter-specific CO_2 emission factors may be used, provided they are developed using methods outlined in § 98.404.

$$CO_{2k} = Fuel \star EF \qquad \text{(Eq. NN-4)}$$

Where:

CO_{2k} = Annual CO_2 mass emissions that would result from the combustion or oxidation of natural gas received by end-users that receive a supply equal to or greater than 460,000 Mscf per year (metric tons).

Fuel = Total annual volume of natural gas supplied (Mscf per year).

EF = Fuel-specific CO_2 emission factor (MT CO_2/Mscf).

(3) For natural gas received by the LDC at the city gate that is injected into on-system storage, and/or liquefied and stored, use Equation NN–5 of this section and the default value for the CO_2 emission factors found in Table NN–2 of this subpart. Alternatively, a reporter-specific CO_2 emission factor may be used, provided it is developed using methods outlined in § 98.404.

$$CO_{2l} = \left[Fuel_1 - Fuel_2\right] \star EF \qquad \text{(Eq. NN-5)}$$

Where:

CO_{2l} = Annual CO_2 mass emissions that would result from the combustion or oxidation of the net natural gas that is liquefied and/or stored and not used for deliveries by the LDC within the reported year (metric tons).

$Fuel_1$ = Total annual volume of natural gas received by the LDC at the city gate and stored on-system or liquefied and stored in the reportng year (Mscf per year).

$Fuel_2$ = Total annual volume of natural gas that is used for deliveries in the reporting year that was not otherwise accounted for in Equation NN–1 or NN–2 of this section (Mscf per year). This primarily includes natural gas previously stored on-system or liquefied and stored that is removed from storage and used for deliveries to customers or other LDCs by the LDC within the reporting year. This also includes natural gas that bypassed the city gate and was delivered directly to LDC systems from producers or natural gas processing plants from local production.

EF = Fuel-specific CO_2 emission factor (MT CO_2/Mscf).

(4) Calculate the total CO_2 emissions that would result from the complete combustion or oxidation of the annual supply of natural gas to end-users using Equation NN–6 of this section.

$$CO_2 = \sum CO_{2i} - \sum CO_{2j} - \sum CO_{2k} - \sum CO_{2l} \qquad \text{(Eq. NN-6)}$$

Where:

CO_2 = Annual CO_2 mass emissions that would result from the combustion or oxidation of natural gas delivered to LDC customers not covered in paragraph (b)(2) of this section (metric tons).

CO_{2i} = Annual CO_2 mass emissions that would result from the combustion or oxidation of natural gas received at the city gate as calculated in paragraph (a)(1) or (a)(2) of this section (metric tons).

CO_{2j} = Annual CO_2 mass emissions that would result from the combustion or oxidation of natural gas delivered to transmission pipelines or other LDCs as calculated in paragraph (b)(1) of this section (metric tons).

CO_{2k} = Annual CO_2 mass emissions that would result from the combustion or oxidation of natural gas received by end-users that receive a supply equal to or greater than 460,000 Mscf per year as calculated in paragraph (b)(2) of this section (metric tons).

CO_{2l} = Annual CO_2 mass emissions that would result from the combustion or oxidation of natural gas received by the LDC and liquefied and/or stored but not used for deliveries within the reported year as calculated in paragraph (b)(3) of this section (metric tons).

(c) Each NGL fractionator shall follow the following procedures.

(1)(i) For fractionated NGLs received by the reporter from other NGL fractionators, you shall use Equation NN–7 of this section and the default values for the CO_2 emission factors found in Table NN–2 of this subpart.

(ii) Alternatively, reporter-specific CO_2 emission factors may be used, provided they are developed using methods outlined in § 98.404.

$$CO_{2m} = \sum_{g} Fuel_g \star EF_g \qquad \text{(Eq. NN-7)}$$

Where:

CO_{2m} = Annual CO_2 mass emissions that would result from the combustion or oxidation of each fractionated NGL product ''g'' received from other fractionators (metric tons).

$Fuel_g$ = Total annual volume of each NGL product ''g'' received (bbls).

EF = Fuel-specific CO_2 emission factor (MT CO_2/bbl).

(2) Calculate the total CO_2 equivalent emissions that would result from the combustion or oxidation of fractionated NGLs supplied less the quantity received by other fractionators using Equation NN–8 of this section.

$$CO_2 = \sum CO_{2i} - \sum CO_{2j} \qquad \text{(Eq. NN-8)}$$

Where:

CO_2 = Annual CO_2 mass emissions that would result from the combustion or oxidation of fractionated NGLs delivered to customers or on behalf of customers (metric tons).

CO_{2i} = Annual CO_2 mass emissions that would result from the combustion or oxidation of fractionated NGLs delivered to all customers as calculated in paragraph (a)(1) or (a)(2) of this section (metric tons).

CO_{2m} = Annual CO_2 mass emissions that would result from the combustion or oxidation of fractionated NGLs received from other fractionators and calculated in paragraph (c)(1) of this section (metric tons).

§ 98.404 Monitoring and QA/QC requirements.

(a) Determination of quantity.

(1) NGL fractionators and LDCs shall determine the quantity of NGLs and natural gas using methods in common use in the industry for billing purposes as audited under existing Sarbanes Oxley regulationn.

(i) Where an appropriate standard method published by a consensus-based standards organization exists, such a method shall be used. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(ii) Where no appropriate standard method developed by a consensus-based standards organization exists, industry standard practices shall be followed.

(2) NGL fractionators and LDCs shall base the minimum frequency of the product quantity measurements, to be summed to the annual quantity reported, on the reporter's standard practices for commercial operations.

(i) For NGL fractionators the minimum frequency of measurements shall be the measurements taken at custody transfers summed to the annual reportable volume.

(ii) For natural gas the minimum frequency of measurement shall be based on the LDC's standard measurement schedules used for billing purposes and summed to the annual reportable volume.

(3) NGL fractionators shall use measurement for NGLs at custody tranfer meters or at such meters that are used to determine the NGL product slate delivered from the fractionation facility.

(4) If a NGL fractionator supplies a product not listed in Table NN–1 of this subpart that is a mixture or blend of two or more products listed in Tables NN–1 and NN–2 of this subpart, the NGL fractionator shall report the quantities of the constituents of the mixtures or blends separately.

(5) For an LDC using Equation NN–1 or NN–2 of this subpart, the point(s) of measurement for the natural gas volume supplied shall be the LDC city gate meter(s).

(i) If the LDC makes its own quantity measurements according to established business practices, its own measurements shall be used.

(ii) If the LDC does not make its own quantity measurements according to established business practices, it shall use its delivering pipeline invoiced measurements for natural gas deliveries to the LDC city gate, used in determining daily system sendout.

(6) An LDC using Equation NN–3 of this subpart shall measure natural gas at the custody transfer meters.

(7) An LDC using Equation NN–4 of this subpart shall measure natural gas at the customer meters. The reporter shall consider the volume delivered through a single particluar meter at a single particular location as the volume delivered to an individual end-user.

(8) An LDC using Equation NN–5 of this subpart shall measure natural gas as follows:

(i) $Fuel_1$ shall be measured at the on-system storage injection meters and/or at the meters measuring natural gas to be liquefied.

(ii) $Fuel_2$ shall be measured at the meters used for measuring on-system storage withdrawals and/or LNG vaporization injection. If $Fuel_2$ is from a source other than storage, the appropriate meter shall be used to measure the quantity.

(9) An LDC shall measure all natural gas under the following standard industry temperature and pressure conditions: Cubic foot of gas at a temperature of 60 degrees Fahrenheit and at an absolute pressure of fourteen and seventy-three hundredths (14.73) pounds per square inch.

(b) Determination of higher heating values (HHV).

(1) When a reporter uses the default HHV provided in this section to calculate Equation NN–1 of this subpart, the appropriate value shall be taken from Table NN–1 of this subpart.

(2) When a reporter uses a reporter-specific HHV to calculate Equation NN–1 of this subpart, an appropriate standard test published by a consensus-based standards organization shall be used. Consensus-based standards organizations include, but are not limited to, the following: AGA and GPA.

(i) If an LDC makes its own HHV measurements according to established business practices, then its own measurements shall be used.

(ii) If an LDC does not make its own measurements according to established business practices, it shall use its delivering pipeline measurements.

(c) Determination of emission factor (EF).

(1) When a reporter used the default EF provided in this section to calculate Equation NN–1 of this subpart, the appropriate value shall be taken from Table NN–1 of this subpart.

(2) When a reporter used the default EF provided in this section to calculate Equation NN–2, NN–3, NN–4, NN–5, or NN–7 of this subpart, the appropriate value shall be taken from Table NN–2 of this subpart.

(3) When a reporter uses a reporter-specific EF, the reporter shall use an appropriate standard method published by a consensus-based standards organization to conduct compositional analysis necessary to determine reporter-specific CO_2 emission factors. Consensus-based standards organizations include, but are not limited to, the following: AGA and GPA.

(d) Equipment Calibration.

(1) Equipment used to measure quantities in Equations NN–1, NN–2, and NN–5 of this subpart shall be calibrated prior to its first use for reporting under this subpart, using a suitable standard method published by a consensus based standards organization or according to the equipment manufacturer's directions.

(2) Equipment used to measure quantities in Equations NN–1, NN–2, and NN–5 of this subpart shall be recalibrated at the frequency specified by the standard method used or by the manufacturer's directions.

§ 98.405 Procedures for estimating missing data.

(a) Whenever a quality-assured value of the quantity of natural gas liquids or natural gas supplied during any period is unavailable (e.g., if a flow meter malfunctions), a substitute data value for the missing quantity measurement must be used in the calculations according to paragraphs (b) and (c) of this section.

(b) Determination of quantity.

(1) NGL fractionators shall substitute meter records provided by pipeline(s) for all pipeline receipts of NGLs; by manifests for deliveries made to trucks or rail cars; or metered quantities accepted by the entities purchasing the output from the fractionator whether by pipeline or by truck or rail car. In cases where the metered data from the receiving pipeline(s) or purchasing entities are not available, fractionators may substitute estimates based on contract quantities required to be delivered under purchase or delivery contracts with other parties.

(2) LDCs shall either substitute their delivering pipeline metered deliveries at the city gate or substitute nominations and scheduled delivery quantities for the period when metered values of actual deliveries are not available.

(c) Determination of HHV and EF.

(1) Whenever an LDC that makes its own HHV measurements according to established business practices cannot follow the quality assurance procedures for developing a reporter-specific HHV, as specified in § 98.404, during any period for any reason, the reporter shall use either its delivering pipeline measurements or the default HHV provided in Table NN–1 of this part for that period.

(2) Whenever an LDC that does not make its own HHV measurements according to established business practices or an NGL fractionator cannot follow the quality assurance procedures for developing a reporter-specific HHV, as specified in § 98.404, during any period for any reason, the reporter shall use the default HHV provided in Table NN–1 of this part for that period.

(3) Whenever a NGL fractionator cannot follow the quality assurance procedures for developing a reporter-specific HHV, as specified in § 98.404, during any period for any reason, the NGL fractionator shall use the default HHV provided in Table NN–1 of this part for that period.

(4) Whenever a reporter cannot follow the quality assurance procedures for developing a reporter-specific EF, as specified in § 98.404, during any period for any reason, the reporter shall use the default EF provided in § 98.408 for that period.

§ 98.406 Data reporting requirements.

(a) In addition to the information required by § 98.3(c), the annual report for each NGL fractionator covered by this rule shall contain the following information.

(1) Annual quantity (in barrels) of each NGL product supplied to downstream facilities in the following product categories: ethane, propane, normal butane, isobutane, and pentanes plus.

(2) Annual quantity (in barrels) of each NGL product received from other NGL fractionators in the following product categories: ethane, propane, normal butane, isobutane, and pentanes plus.

(3) Annual volumes in Mscf of natural gas received for processing.

(4) Annual quantity (in barrels) of y-grade, bulk NGLs received from others for fractionation.

(5) Annual quantity (in barrels) of propane that the NGL fractionator odorizes at the facility and delivers to others.

(6) Annual CO_2 emissions (metric tons) that would result from the complete combustion or oxidation of the quantities in paragraphs (b)(1) and (b)(2) of this section, calculated in accordance with § 98.403(a) and (c)(1).

(7) Annual CO_2 mass emissions (metric tons) that would result from the combustion or oxidation of fractionated NGLs supplied less the quantity received by other fractionators, calculated in accordance with § 98.403(c)(2).

(8) The specific industry standard used to measure each quantity reported in paragraph (a)(1) of this section.

(9) If the LNG fractionator developed reporter-specific EFs or HHVs, report the following:

(i) The specific industry standard(s) used to develop reporter-specific higher heating value(s) and/or emission factor(s), pursuant to § 98.404(b)(2) and (c)(3).

(ii) The developed HHV(s).

(iii) The developed EF(s).

(b) In addition to the information required by § 98.3(c), the annual report for each LDC shall contain the following information.

(1) Annual volume in Mscf of natural gas received by the LDC at its city gate stations for redelivery on the LDC's distribution system, including for use by the LDC.

(2) Annual volume in Mscf of natural gas placed into storage.

(3) Annual volume in Mscf of vaporized liquefied natural gas (LNG) produced at on-system vaporization facilities for delivery on the distribution system that is not accounted for in paragraph (b)(1) of this section.

(4) Annual volume in Mscf of natural gas withdrawn from on-system storage (that is not delivered to the city gate) for delivery on the distribution system.

(5) Annual volume in Mscf of natural gas delivered directly to LDC systems from producers or natural gas processing plants from local production.

(6) Annual volume in Mscf of natural gas delivered to downstream gas transmission pipelines and other local distribution companies.

(7) Annual volume in Mscf of natural gas delivered by LDC to each meter registering supply equal to or greater than 460,000 Mcsf during the calendar year.

(8) The total annual CO_2 mass emissions (metric tons) associated with the volumes in paragraphs (b)(1) through (b)(7) of this section, calculated in accordance with § 98.403(a) and (b)(1) through (b)(3).

(9) Annual CO_2 emissions (metric tons) that would result from the complete combustion or oxidation of the annual supply of natural gas to end-users registering less than 460,000 Mcsf, calculated in accordance with § 98.403(b)(4).

(10) The specific industry standard used to develop the volume reported in paragraph (b)(1) of this section.

(11) If the LDC developed reporter-specific EFs or HHVs, report the following:

(i) The specific industry standard(s) used to develop reporter-specific higher heating value(s) and/or emission factor(s), pursuant to § 98.404 (b)(2) and (c)(3).

(ii) The developed HHV(s).

(iii) The developed EF(s).

(12) The customer name, address, and meter number of each meter reading used to report in paragraph (b)(7) of this section.

(i) If known, report the EIA identification number of each LDC customer.

(ii) [Reserved]

(13) The annual volume in Mscf of natural gas delivered by the local distribution company to each of the following end-use categories. For definitions of these categories, refer to EIA Form 176 (Annual Report of Natural Gas and Supplemental Gas Supply & Disposition) and Instructions.

(i) Residential consumers.

(ii) Commercial consumers.

(iii) Industrial consumers.

(iv) Electricity generating facilities.

(c) Each reporter shall report the number of days in the reporting year for which substitute data procedures were used for the following purpose:

(1) To measure quantity.

(2) To develop HHV(s).

(3) To develop EF(s).

§ 98.407 Records that must be retained.

In addition to the information required by § 98.3(g), each annual report must contain the following information:

(a) Records of all daily meter readings and documentation to support volumes of natural gas and NGLs that are reported under this part.

(b) Records documenting any estimates of missing metered data and showing the calculations of the values used for the missing data.

(c) Calculations and worksheets used to estimate CO_2 emissions for the volumes reported under this part.

(d) Records related to the large end-users identified in § 98.406(b)(6).

(e) Records relating to measured Btu content or carbon content showing specific industry standards used to develop reporter-specific higher heating values and emission factors.

(f) Records of such audits as required by Sarbanes Oxley regulations on the accuracy of measurements of volumes of natural gas and NGLs delivered to customers or on behalf of customers.

§ 98.408 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE NN–1 TO SUBPART NN OF PART 98—DEFAULT FACTORS FOR CALCULATION METHODOLOGY 1 OF THIS SUBPART

Fuel	Default high heating value factor	Default CO_2 emission factor (kg CO_2/MMBtu)
Natural Gas	1.027 MMBtu/Mscf	53.02
Propane	3.836 MMBtu/bbl	63.02
Normal butane	4.326 MMBtu/bbl	64.93
Ethane	3.082 MMBtu/bbl	59.58
Isobutane	3.974 MMBtu/bbl	65.08
Pentanes plus	4.620 MMBtu/bbl	66.90

TABLE NN–2 TO SUBPART NN OF PART 98—LOOKUP DEFAULT VALUES FOR CALCULATION METHODOLOGY 2 OF THIS SUBPART

Fuel	Unit	Default CO_2 emission value (MT CO_2/Unit)
Natural Gas	Mscf	0.054452
Propane	Barrel	0.241745
Normal butane	Barrel	0.280887
Ethane	Barrel	0.183626
Isobutane	Barrel	0.258628

TABLE NN–2 TO SUBPART NN OF PART 98—LOOKUP DEFAULT VALUES FOR CALCULATION METHODOLOGY 2 OF THIS SUBPART—Continued

Fuel	Unit	Default CO_2 emission value ($MT\ CO_2$/Unit)
Pentanes plus	Barrel	0.309078

Subpart OO—Suppliers of Industrial Greenhouse Gases

§ 98.410 Definition of the source category.

(a) The industrial gas supplier source category consists of any facility that produces a fluorinated GHG or nitrous oxide, any bulk importer of fluorinated GHGs or nitrous oxide, and any bulk exporter of fluorinated GHGs or nitrous oxide.

(b) To produce a fluorinated GHG means to manufacture a fluorinated GHG from any raw material or feedstock chemical. Producing a fluorinated GHG includes the manufacture of a fluorinated GHG for use in a process that will result in its transformation either at or outside of the production facility. Producing a fluorinated GHG also includes the creation of a fluorinated GHG (with the exception of HFC–23) that is captured and shipped off site for any reason, including destruction. Producing a fluorinated GHG does not include the reuse or recycling of a fluorinated GHG, the creation of HFC–23 during the production of HCFC–22, or the creation of by-products that are released or destroyed at the production facility.

(c) To produce nitrous oxide means to produce nitrous oxide by thermally decomposing ammonium nitrate (NH_4NO_3). Producing nitrous oxide does not include the reuse or recycling of nitrous oxide or the creation of by-products that are released or destroyed at the production facility.

§ 98.411 Reporting threshold.

Any supplier of industrial greenhouse gases who meets the requirements of § 98.2(a)(4) must report GHG emissions.

§ 98.412 GHGs to report.

You must report the GHG emissions that would result from the release of the nitrous oxide and each fluorinated GHG that you produce, import, export, transform, or destroy during the calendar year.

§ 98.413 Calculating GHG emissions.

(a) Calculate the total mass of each fluorinated GHG or nitrous oxide produced annually, except for amounts that are captured solely to be shipped off site for destruction, by using Equation OO–1 of this section:

$$P = \sum_{p=1}^{n} P_p \qquad \text{(Eq. OO-1)}$$

P = Mass of fluorinated GHG or nitrous oxide produced annually.

P_p = Mass of fluorinated GHG or nitrous oxide produced over the period ''p''.

(b) Calculate the total mass of each fluorinated GHG or nitrous oxide produced over the period ''p'' by using Equation OO–2 of this section:

$$P_p = O_p - U_p \qquad \text{(Eq. OO-2)}$$

Where:

P_p = Mass of fluorinated GHG or nitrous oxide produced over the period ''p'' (metric tons).

O_p = Mass of fluorinated GHG or nitrous oxide that is measured coming out of the production process over the period p (metric tons).

U_p = Mass of used fluorinated GHG or nitrous oxide that is added to the production process upstream of the output measurement over the period ''p'' (metric tons).

(c) Calculate the total mass of each fluorinated GHG or nitrous oxide transformed by using Equation OO–3 of this section:

$$T = F_T * E_T \qquad \text{(Eq. OO-3)}$$

Where:

T = Mass of fluorinated GHG or nitrous oxide transformed annually (metric tons).

F_T = Mass of fluorinated GHG fed into the transformation process annually (metric tons).

E_T = The fraction of the fluorinated GHG or nitrous oxide fed into the transformation process that is transformed in the process (metric tons).

(d) Calculate the total mass of each fluorinated GHG destroyed by using Equation OO–4 of this section:

$$D = F_D * DE \qquad \text{(Eq. OO-4)}$$

Where:

D = Mass of fluorinated GHG destroyed annually (metric tons).

F_D = Mass of fluorinated GHG fed into the destruction device annually (metric tons).

DE = Destruction efficiency of the destruction device (fraction).

§ 98.414 Monitoring and QA/QC requirements.

(a) The mass of fluorinated GHGs or nitrous oxide coming out of the production process shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better.

(b) The mass of any used fluorinated GHGs or used nitrous oxide added back into the production process upstream of the output measurement in paragraph (a) of this section shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better. If the mass in paragraph (a) of this section is measured by weighing containers that include returned heels as well as newly produced fluorinated GHGs, the returned heels shall be considered used fluorinated GHGs for purposes of this paragraph (b) of this section and § 98.413(b).

(c) The mass of fluorinated GHGs or nitrous oxide fed into the transformation process shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better.

(d) The fraction of the fluorinated GHGs or nitrous oxide fed into the transformation process that is actually transformed shall be estimated considering yield calculations or quantities of unreacted fluorinated GHGs or nitrous oxide permanently removed from the process and recovered, destroyed, or emitted.

(e) The mass of fluorinated GHG or nitrous oxide sent to another facility for transformation shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better.

(f) The mass of fluorinated GHG sent to another facility for destruction shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the fluorinated GHG, the concentration of the fluorinated GHG shall be estimated considering current or previous representative concentration measurements and other relevant process information. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the fluorinated GHG sent to another facility for destruction.

(g) You must estimate the share of the mass of fluorinated GHGs in paragraph (f) of this section that is comprised of fluorinated GHGs that are not included in the mass produced in § 98.413(a) because they are removed from the production process as by-products or other wastes.

(h) The mass of fluorinated GHGs fed into the destruction device shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the fluorinated GHG being destroyed, the concentrations of fluorinated GHG being destroyed shall be estimated considering current or previous representative concentration measurements and other relevant process information. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the fluorinated GHG destroyed.

(i) Very small quantities of fluorinated GHGs that are difficult to measure because they are entrained in other media such as destroyed filters and destroyed sample containers are exempt from paragraphs (f) and (h) of this section.

(j) You must estimate the share of the mass of fluorinated GHGs in paragraph (h) of this section that is comprised of fluorinated GHGs that are not included in the mass produced in § 98.413(a) because they are removed from the production process as by-products or other wastes.

(k) For purposes of Equation OO–4 of this subpart, the destruction efficiency can be equated to the destruction efficiency determined during a previous performance test of the destruction device or, if no performance test has been done, the destruction efficiency provided by the manufacturer of the destruction device.

(l) In their estimates of the mass of fluorinated GHGs destroyed, fluorinated GHG production facilities that destroy fluorinated GHGs shall account for any temporary reductions in the destruction efficiency that result from any startups, shutdowns, or malfunctions of the destruction device, including departures from the operating conditions defined in state or local permitting requirements and/or oxidizer manufacturer specifications.

(m) Calibrate all flow meters, weigh scales, and combinations of volumetric and density measures that are used to measure or calculate quantities that are to be reported under this subpart prior to the first year for which GHG emissions are reported under this part. Calibrations performed prior to the effective date of this rule satisfy this requirement. Recalibrate all flow meters, weigh scales, and combinations of volumetric and density measures at the minimum frequency specified by the manufacturer. Use NIST-traceable standards and suitable methods published by a consensus standards organization (e.g., ASTM, ASME, ISO, or others).

§ 98.415 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions), a substitute data value for the missing parameter shall be used in the calculations, according to paragraph (b) of this section.

(b) For each missing value of the mass produced, fed into the production process (for used material being reclaimed), fed into the transformation process, fed into destruction devices, sent to another facility for transformation, or sent to another facility for destruction, the substitute value of that parameter shall be a secondary mass measurement where such a measurement is available. For example, if the mass produced is usually measured with a flowmeter at the inlet to the day tank and that flowmeter fails to meet an accuracy or precision test, malfunctions, or is rendered inoperable, then the mass produced may be estimated by calculating the change in volume in the day tank and multiplying it by the density of the product. Where a secondary mass measurement is not available, the substitute value of the parameter shall be an estimate based on a related parameter. For example, if a flowmeter measuring the mass fed into a destruction device is rendered inoperable, then the mass fed into the destruction device may be estimated using the production rate and the previously observed relationship between the production rate and the mass flow rate into the destruction device.

§ 98.416 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information:

(a) Each fluorinated GHG or nitrous oxide production facility shall report the following information:

(1) Mass in metric tons of each fluorinated GHG or nitrous oxide produced at that facility by process, except for amounts that are captured solely to be shipped off site for destruction.

(2) Mass in metric tons of each fluorinated GHG or nitrous oxide transformed at that facility, by process.

(3) Mass in metric tons of each fluorinated GHG destroyed at that facility, except fluorinated GHGs not included in the calculation of mass produced in § 98.413(a) because they are removed from the production process as by-products or other wastes. Quantities to be reported under this paragraph (a)(3) of this section could include, for example, quantities that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore destroyed.

(4) Mass in metric tons of each fluorinated GHG that is destroyed at that facility except GHGs not included in the calculation of mass produced in § 98.413(a) because they are removed from the production process as byproducts or other wastes.

(5) Total mass in metric tons of each fluorinated GHG or nitrous oxide sent to another facility for transformation.

(6) Total mass in metric tons of each fluorinated GHG sent to another facility for destruction, except fluorinated GHGs that are not included in the mass produced in § 98.413(a) because they are removed from the production process as by-products or other wastes. Quantities to be reported under this paragraph (a)(6) could include, for example, fluorinated GHGs that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore sent to another facility for destruction.

(7) Total mass in metric tons of each fluorinated GHG that is sent to another facility for destruction and that is not included in the mass produced in § 98.413(a) because it is removed from

the production process as a byproduct or other waste.

(8) Total mass in metric tons of each reactant fed into the F–GHG or nitrous oxide production process, by process.

(9) Total mass in metric tons of the reactants, by-products, and other wastes permanently removed from the F–GHG or nitrous oxide production process, by process.

(10) For transformation processes that do not produce an F–GHG or nitrous oxide, mass in metric tons of any fluorinated GHG or nitrous oxide fed into the transformation process, by process.

(11) Mass in metric tons of each fluorinated GHG fed into the destruction device.

(12) Mass in metric tons of each fluorinated GHG or nitrous oxide that is measured coming out of the production process, by process.

(13) Mass in metric tons of each used fluorinated GHGs or nitrous oxide added back into the production process (e.g., for reclamation), including returned heels in containers that are weighed to measure the mass in § 98.414(a), by process.

(14) Names and addresses of facilities to which any nitrous oxide or fluorinated GHGs were sent for transformation, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sent to each for transformation.

(15) Names and addresses of facilities to which any fluorinated GHGs were sent for destruction, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sent to each for destruction.

(16) Where missing data have been estimated pursuant to § 98.415, the reason the data were missing, the length of time the data were missing, the method used to estimate the missing data, and the estimates of those data.

(b) A fluorinated GHG production facility or importer that destroys fluorinated GHGs shall submit a one-time report containing the following information:

(1) Destruction efficiency (DE) of each destruction unit.

(2) Methods used to determine the destruction efficiency.

(3) Methods used to record the mass of fluorinated GHG destroyed.

(4) Chemical identity of the fluorinated GHG(s) used in the performance test conducted to determine DE.

(5) Name of all applicable federal or state regulations that may apply to the destruction process.

(6) If any process changes affect unit destruction efficiency or the methods used to record mass of fluorinated GHG destroyed, then a revised report must be submitted to reflect the changes. The revised report must be submitted to EPA within 60 days of the change.

(c) A bulk importer of fluorinated GHGs or nitrous oxide shall submit an annual report that summarizes their imports at the corporate level, except for shipments including less than 250 metric tons of CO_2e, transshipments, and heels that meet the conditions set forth at § 98.417(e). The report shall contain the following information for each import:

(1) Total mass in metric tons of nitrous oxide and each fluorinated GHG imported in bulk.

(2) Total mass in metric tons of nitrous oxide and each fluorinated GHG imported in bulk and sold or transferred to persons other than the importer for use in processes resulting in the transformation or destruction of the chemical.

(3) Date on which the fluorinated GHGs or nitrous oxide were imported.

(4) Port of entry through which the fluorinated GHGs or nitrous oxide passed.

(5) Country from which the imported fluorinated GHGs or nitrous oxide were imported.

(6) Commodity code of the fluorinated GHGs or nitrous oxide shipped.

(7) Importer number for the shipment.

(8) Total mass in metric tons of each fluorinated GHG destroyed by the importer.

(9) If applicable, the names and addresses of the persons and facilities to which the nitrous oxide or fluorinated GHGs were sold or transferred for transformation, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sold or transferred to each facility for transformation.

(10) If applicable, the names and addresses of the persons and facilities to which the nitrous oxide or fluorinated GHGs were sold or transferred for destruction, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sold or transferred to each facility for destruction.

(d) A bulk exporter of fluorinated GHGs or nitrous oxide shall submit an annual report that summarizes their exports at the corporate level, except for shipments including less than 250 metric tons of CO_2e, transshipments, and heels. The report shall contain the following information for each export:

(1) Total mass in metric tons of nitrous oxide and each fluorinated GHG exported in bulk.

(2) Names and addresses of the exporter and the recipient of the exports.

(3) Exporter's Employee Identification Number.

(4) Commodity code of the fluorinated GHGs and nitrous oxide shipped.

(5) Date on which, and the port from which, fluorinated GHGs and nitrous oxide were exported from the United States or its territories.

(6) Country to which the fluorinated GHGs or nitrous oxide were exported.

(e) By April 1, 2011, a fluorinated GHG production facility shall submit a one-time report describing the following information:

(1) The method(s) by which the producer in practice measures the mass of fluorinated GHGs produced, including the instrumentation used (Coriolis flowmeter, other flowmeter, weigh scale, etc.) and its accuracy and precision.

(2) The method(s) by which the producer in practice estimates the mass of fluorinated GHGs fed into the transformation process, including the instrumentation used (Coriolis flowmeter, other flowmeter, weigh scale, etc.) and its accuracy and precision.

(3) The method(s) by which the producer in practice estimates the fraction of fluorinated GHGs fed into the transformation process that is actually transformed, and the estimated precision and accuracy of this estimate.

(4) The method(s) by which the producer in practice estimates the masses of fluorinated GHGs fed into the destruction device, including the method(s) used to estimate the concentration of the fluorinated GHGs in the destroyed material, and the estimated precision and accuracy of this estimate.

(5) The estimated percent efficiency of each production process for the fluorinated GHG produced.

§ 98.417 Records that must be retained.

(a) In addition to the data required by § 98.3(g), the fluorinated GHG production facility shall retain the following records:

(1) Dated records of the data used to estimate the data reported under § 98.416.

(2) Records documenting the initial and periodic calibration of the gas chromatographs, weigh scales, flowmeters, and volumetric and density measures used to measure the quantities reported under this subpart, including the industry standards or manufacturer directions used for calibration pursuant to § 98.414(j) and (k).

(b) In addition to the data required by paragraph (a) of this section, the fluorinated GHG production facility that destroys fluorinated GHGs shall keep records of test reports and other information documenting the facility's one-time destruction efficiency report and annual destruction device outlet reports in § 98.416(b) and (e).

(c) In addition to the data required by § 98.3(g), the bulk importer shall retain the following records substantiating each of the imports that they report:

(1) A copy of the bill of lading for the import.

(2) The invoice for the import.

(3) The U.S. Customs entry form.

(d) In addition to the data required by § 98.3(g), the bulk exporter shall retain the following records substantiating each of the exports that they report:

(1) A copy of the bill of lading for the export and

(2) The invoice for the import.

(e) Every person who imports a container with a heel that is not reported under § 98.416(c) shall keep records of the amount brought into the United States that document that the residual amount in each shipment is less than 10 percent of the volume of the container and will:

(1) Remain in the container and be included in a future shipment.

(2) Be recovered and transformed.

(3) Be recovered and destroyed.

(4) Be recovered and included in a future shipment.

§ 98.418 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart PP—Suppliers of Carbon Dioxide

§ 98.420 Definition of the source category.

(a) The carbon dioxide (CO_2) supplier source category consists of the following:

(1) Facilities with production process units 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. Capture refers to the initial separation and removal of CO_2 from a manufacturing process or any other process.

(2) Facilities with CO_2 production wells that extract or produce a CO_2 stream for purposes of supplying CO_2 for commercial applications or that extract and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground.

(3) Importers or exporters of bulk CO_2.

(b) This source category is focused on upstream supply. It does not cover:

(1) Storage of CO_2 above ground or in geologic formations.

(2) Use of CO_2 in enhanced oil and gas recovery.

(3) Transportation or distribution of CO_2.

(4) Purification, compression, or processing of CO_2.

(5) On-site use of CO_2 captured on site.

(c) This source category does not include CO_2 imported or exported in equipment, such as fire extinguishers.

§ 98.421 Reporting threshold.

Any supplier of CO_2 who meets the requirements of § 98.2(a)(4) of subpart A of this part must report the mass of CO_2 captured, extracted, imported, or exported.

§ 98.422 GHGs to report.

(a) Mass of CO_2 captured from each production process unit.

(b) Mass of CO_2 extracted from each CO_2 production wells.

(c) Mass of CO_2 imported.

(d) Mass of CO_2 exported.

§ 98.423 Calculating CO_2 supply.

(a) Calculate the annual mass of CO_2 captured, extracted, imported, or exported through each flow meter in accordance with the procedures specified in either paragraph (a)(1) or (a)(2) of this section. If multiple flow meters are used, you shall calculate the annual mass of CO_2 for all flow meters according to the procedures specified in paragraph (a)(3) of this section.

(1) For each mass flow meter, you shall calculate quarterly the mass of CO_2 in a CO_2 stream in metric tons, prior to any subsequent purification, processing, or compressing, by multiplying the mass flow by the composition data, according to Equation PP–1 of this section. Mass flow and composition data measurements shall be made in accordance with § 98.424 of this subpart.

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_{2,p,u}} \qquad \text{(Eq. PP-1)}$$

Where:

$CO_{2,u}$ = Annual mass of CO_2 (metric tons) through flow meter u.

$C_{CO_2,p,u}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (wt. %CO_2).

$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons).

p = Quarter of the year.

u = Flow meter.

(2) For each volumetric flow meter, you shall calculate quarterly the mass of CO_2 in a CO_2 stream in metric tons, prior to any subsequent purification, processing, or compressing, by multiplying the volumetric flow by the concentration and density data, according to Equation PP–2 of this section. Volumetric flow, concentration and density data measurements shall be made in accordance with § 98.424 of this section.

$$CO_{2,u} = \sum_{p=1}^{4} Q_p * D_p * C_{CO_{2,p}} \qquad \text{(Eq. PP-2)}$$

Where:

$CO_{2,u}$ = Annual mass of CO_2 (metric tons) through flow meter u.

$C_{CO_2,p}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (wt. % CO_2).

Q_p = Quarterly volumetric flow rate measurement for flow meter u in quarter p (standard cubic meters).

D_p = Quarterly CO_2 stream density measurement for flow meter u in quarter p (metric tons per standard cubic meter).

p = Quarter of the year.

u = Flow meter.

(3) To aggregate data, sum the mass of CO_2 for all flow meters in accordance with Equation PP–3 of this section.

$$CO_2 = \sum_{p=1}^{U} CO_{2,u} \qquad \text{(Eq. PP-3)}$$

Where:

CO_2 = Annual mass of CO_2 (metric tons) through all flow meters.

$CO_{2,u}$ = Annual mass of CO_2 (metric tons) through flow meter u.

u = Flow meter.

(b) Importers or exporters that import or export CO_2 in containers shall calculate the total mass of CO_2 imported or exported in metric tons, prior to any subsequent purification, processing, or compressing, based on summing the mass in each CO_2 container using weigh bills, scales, or load cells according to Equation PP–4 of this section.

$$CO_2 = \sum_{p=1}^{I} Q \qquad \text{(Eq. PP-4)}$$

Where:

CO_2 = Annual mass of CO_2 (metric tons).

Q = Annual mass in all CO_2 containers imported or exported during the reporting year (metric tons).

§ 98.424 Monitoring and QA/QC requirements.

(a) Determination of quantity.

(1) Reporters that have a mass flow meter or volumetric flow meter installed to measure the flow of a CO_2 stream shall base calculations in § 98.423 of this subpart on the installed mass flow or volumetric flow meters.

(2) Reporters that do not have a mass flow meter or volumetric flow meter installed to measure the flow of the CO_2 stream shall base calculations in § 98.423 of this subpart on the flow of gas transferred off site using a mass flow meter or a volumetric flow meter located at the point of off-site transfer.

(3) Importers or exporters that import or export CO_2 in containers shall measure the mass in each CO_2 container using weigh bills, scales, or load cells and sum the mass in all containers imported or exported during the reporting year.

(4) All flow meters, scales, and load cells used to measure quantities that are reported in § 98.423 of this subpart shall be operated and calibrated according to the following procedure:

(i) You shall use an appropriate standard method published by a consensus-based standards organization if such a method exists. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(ii) Where no appropriate standard method developed by a consensus-based standards organization exists, you shall follow industry standard practices.

(iii) You must ensure that any flow meter calibrations performed are NIST traceable.

(5) Reporters using Equation PP–2 of this subpart shall measure the density of the CO_2 stream on a quarterly basis in order to calculate the mass of the CO_2 stream according to the following procedure:

(i) You shall use an appropriate standard method published by a consensus-based standards organization to measure density if such a method exists. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(ii) Where no appropriate standard method developed by a consensus-based standards organization exists, you shall follow industry standard practices.

(b) Determination of concentration.

(1) Reporters using Equation PP–1 or PP–2 of this subpart shall sample the CO_2 stream on a quarterly basis to determine the composition of the CO_2 stream.

(2) Methods to measure the composition of the CO_2 stream must conform to applicable chemical analytical standards. Acceptable methods include U.S. Food and Drug Administration food-grade specifications for CO_2 (see 21 CFR 184.1250) and ASTM standard E1747–95 (Reapproved 2005) Standard Guide for Purity of Carbon Dioxide Used in Supercritical Fluid Applications (incorporated by reference, see § 98.7 of subpart A of this part).

§ 98.425 Procedures for estimating missing data.

(a) Whenever the quality assurance procedures in § 98.424(a) of this subpart cannot be followed to measure quarterly mass flow or volumetric flow of CO_2, the most appropriate of the following missing data procedures shall be followed:

(1) A quarterly CO_2 mass flow or volumetric flow value that is missing may be substituted with a quarterly value measured during another quarter of the current reporting year.

(2) A quarterly CO_2 mass flow or volumetric flow value that is missing may be substituted with a quarterly value measured during the same quarter from the past reporting year.

(3) If a mass or volumetric flow meter is installed to measure the CO_2 stream, you may substitute data from a mass or volumetric flow meter measuring the CO_2 stream transferred for any period during which the installed meter is inoperable.

(4) The mass or volumetric flow used for purposes of product tracking and billing according to the reporter's established procedures may be substituted for any period during which measurement equipment is inoperable.

(b) Whenever the quality assurance procedures in § 98.424(b) of this subpart cannot be followed to determine concentration of the CO_2 stream, the most appropriate of the following missing data procudures shall be followed:

(1) A quarterly concentration value that is missing may be substituted with a quarterly value measured during another quarter of the current reporting year.

(2) A quarterly concentration value that is missing may be substituted with a quarterly value measured during the same quarter from the previous reporting year.

(3) The concentration used for purposes of product tracking and billing according to the reporter's established procedures may be substituted for any quarterly value.

(c) Missing data on density of the CO_2 stream shall be substituted with quarterly or annual average values from the previous calendar year.

§ 98.426 Data reporting requirements.

In addition to the information required by § 98.3(c) of subpart A of this part, the annual report shall contain the following information, as applicable:

(a) If you use Equation PP–1 of this subpart, report the following information for each mass flow meter:

(1) Annual mass in metric tons of CO_2.

(2) Quarterly mass flow of CO_2.

(3) Quarterly concentration of the CO_2 stream.

(4) The standard used to measure CO_2 concentration.

(b) If you use Equation PP–2 of this subpart, report the following information for each volumetric flow meter:

(1) Annual mass in metric tons of CO_2.

(2) Quarterly volumetric flow of CO_2.

(3) Quarterly concentration of the CO_2 stream.

(4) Quarterly density of the CO_2 stream.

(5) The method used to measure density.

(6) The standard used to measure CO_2 concentration.

(c) If you use Equation PP–3 of this subpart, report the annual CO_2 mass in metric tons from all flow meters.

(d) If you use Equation PP–4 of this subpart, report at the corporate level the annual mass of CO_2 in metric tons in all CO_2 containers that are imported or exported.

(e) Each reporter shall report the following information:

(1) The type of equipment used to measure the total flow of the CO_2 stream or the total mass in CO_2 containers.

(2) The standard used to operate and calibrate the equipment reported in (e)(1) of this section.

(3) The number of days in the reporting year for which substitute data procedures were used for the following purpose:

(i) To measure quantity.

(ii) To measure concentration.

(iii) To measure density.

(f) Report the aggregated annual quantity of CO_2 in metric tons that is transferred to each of the following end use applications, if known:

(1) Food and beverage.

(2) Industrial and municipal water/wastewater treatment.

(3) Metal fabrication, including welding and cutting.

(4) Greenhouse uses for plant growth.

(5) Fumigants (e.g., grain storage) and herbicides.

(6) Pulp and paper.

(7) Cleaning and solvent use.

(8) Fire fighting.

(9) Transportation and storage of explosives.

(10) Enhanced oil and natural gas recovery.

(11) Long-term storage (sequestration).

(12) Research and development.

(13) Other.

(g) Each production process unit that captures a CO_2 stream for purposes of supplying CO_2 for commercial applications or in order to sequester or otherwise inject it underground when custody of the CO_2 is maintained shall report the percentage of that stream, if any, that is biomass-based during the reporting year.

§ 98.427 Records that must be retained.

In addition to the records required by § 98.3(g) of subpart A of this part, you must retain the records specified in paragraphs (a) through (c) of this section, as applicable.

(a) The owner or operator of a facility containing production process units must retain quarterly records of captured or transferred CO_2 streams and composition.

(b) The owner or operator of a CO_2 production well facility must maintain quarterly records of the mass flow or volumetric flow of the extracted or transferred CO_2 stream and concentration and density if volumetric flow meters are used.

(c) Importers or exporters of CO_2 must retain annual records of the mass flow, volumetric flow, and mass of CO_2 imported or exported.

§ 98.428 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

PART 1033—[AMENDED]

■ 21. The authority citation for part 1033 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart C—[Amended]

■ 22. Section 1033.205 is amended by revising paragraph (d)(8) to read as follows:

§ 1033.205 Applying for a certificate of conformity.

* * * * *

(d) * * *

(8)(i) All test data you obtained for each test engine or locomotive. As described in § 1033.235, we may allow you to demonstrate compliance based on results from previous emission tests, development tests, or other testing information. Include data for NOx, PM, HC, CO, and CO_2.

(ii) Report measured CO_2, N_2O, and CH_4 as described in § 1033.235. Small manufacturers/remanufacturers may omit reporting N_2O and CH_4.

* * * * *

■ 23. Section 1033.235 is amended by adding paragraph (i) to read as follows:

§ 1033.235 Emission testing required for certification.

* * * * *

(i) Measure CO_2 with each test. Measure CH_4 with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting in the 2012 model year. Also measure N_2O with each low-hour certification test using the procedures specified in 40 CFR part 1065 for any engine family that depends on NOx aftertreatment to meet emission standards. Small manufacturers/remanufacturers may omit measurement of N_2O and CH_4. Use the same units and modal calculations as for your other results to report a single weighted value for CO_2, N_2O, and CH_4. Round the final values as follows:

(1) Round CO_2 to the nearest 1 g/bhp–hr.

(2) Round N_2O to the nearest 0.001 g/bhp–hr.

(3) Round CH_4 to the nearest 0.001g/bhp–hr.

Subpart F—[Amended]

■ 24. Section 1033.501 is amended by revising paragraph (a) introductory text to read as follows:

§ 1033.501 General provisions.

(a) Except as specified in this subpart, use the equipment and procedures for compression-ignition engines in 40 CFR part 1065 to determine whether your locomotives meet the duty-cycle emission standards in § 1033.101. Use the applicable duty cycles specified in this subpart. Measure emissions of all the pollutants we regulate in § 1033.101 plus CO_2. Measure N_2O, and CH_4 as described in § 1033.235. The general test procedure is the procedure specified in 40 CFR part 1065 for steady-state discrete-mode cycles. However, if you use the optional ramped modal cycle in § 1033.520, follow the procedures for ramped modal testing in 40 CFR part 1065. The following exceptions from the 1065 procedures apply:

* * * * *

Subpart J—[Amended]

■ 25. Section 1033.905 is amended by adding the abbreviations CH_4 and N_2O in alphanumeric order to read as follows:

§ 1033.905 Symbols, acronyms, and abbreviations.

* * * * *

* * * * *

CH_4 methane.

* * * * *

N_2O nitrous oxide.

* * * * *

PART 1039—[AMENDED]

■ 26. The authority citation for part 1039 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart C—[Amended]

■ 27. Section 1039.205 is amended by revising paragraph (r) to read as follows:

§ 1039.205 What must I include in my application?

* * * * *

(r) Report test results as follows:

(1) Report all test results involving measurement of pollutants for which emission standards apply. Include test results from invalid tests or from any other tests, whether or not they were conducted according to the test

procedures of subpart F of this part. We may ask you to send other information to confirm that your tests were valid under the requirements of this part and 40 CFR part 1065.

(2) Report measured CO_2, N_2O, and CH_4 as described in § 1039.235. Small-volume engine manufacturers may omit reporting N_2O and CH_4.

* * * * *

■ 28. Section 1039.235 is amended by adding paragraph (g) to read as follows:

§ 1039.235 What emission testing must I perform for my application for a certificate of conformity?

* * * * *

(g) Measure CO_2 and CH_4 with each low-hour certification test using the procedures specified in 40 CFR part 1065 in the 2011 and 2012 model years, respectively. Also measure N_2O with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting in the 2013 model year for any engine family that depends on NOx aftertreatment to meet emission standards. Small-volume engine manufacturers may omit measurement of N_2O and CH_4. These measurements are not required for NTE testing. Use the same units and modal calculations as for your other results to report a single weighted value for each constituent. Round the final values as follows:

(1) Round CO_2 to the nearest 1 g/kW-hr.

(2) Round N_2O to the nearest 0.001 g/kW-hr.

(3) Round CH_4 to the nearest 0.001g/kW-hr.

Subpart F—[Amended]

■ 29. Section 1039.501 is amended by revising paragraph (a) to read as follows:

§ 1039.501 How do I run a valid emission test?

(a) Use the equipment and procedures for compression-ignition engines in 40 CFR part 1065 to determine whether engines meet the duty-cycle emission standards in subpart B of this part. Measure the emissions of all the exhaust constituents subject to emissions standards as specified in 40 CFR part 1065. Measure CO_2, N_2O, and CH_4 as described in § 1039.235. Use the applicable duty cycles specified in §§ 1039.505 and 1039.510.

* * * * *

Subpart I—[Amended]

■ 30. Section 1039.805 is amended by adding the abbreviations CH_4 and N_2O in alphanumeric order to read as follows:

§ 1039.805 What symbols, acronyms, and abbreviations does this part use?

* * * * *

* * * * *

CH_4 methane.

* * * * *

N_2O nitrous oxide.

* * * * *

PART 1042—[AMENDED]

■ 31. The authority citation for part 1042 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart C—[Amended]

■ 32. Section 1042.205 is amended by revising paragraph (r) to read as follows:

§ 1042.205 Application requirements.

* * * * *

(r) Report test results as follows:

(1) Report all test results involving measurement of pollutants for which emission standards apply. Include test results from invalid tests or from any other tests, whether or not they were conducted according to the test procedures of subpart F of this part. We may ask you to send other information to confirm that your tests were valid under the requirements of this part and 40 CFR part 1065.

(2) Report measured CO_2, N_2O, and CH_4 as described in § 1042.235. Small-volume engine manufacturers may omit reporting N_2O and CH_4.

* * * * *

■ 33. Section 1042.235 is amended by adding paragraph (g) to read as follows:

§ 1042.235 Emission testing required for a certificate of conformity.

* * * * *

(g) Measure CO_2 with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting in the 2011 model year. Also measure CH_4 from Category 1 and Category 2 engines with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting in the 2012 model year. Measure N_2O from Category 1 and Category 2 engines with each low-hour certification test using the procedures specified in 40 CFR part 1065 for any engine family that depends on NOx aftertreatment to meet emission standards. Small-volume engine manufacturers may omit measurement of N_2O and CH_4. These measurements are not required for NTE testing. Use the same units and modal calculations as for your other results to report a single weighted value for each constituent. Round the final values as follows:

(1) Round CO_2 to the nearest 1 g/kW-hr.

(2) Round N_2O to the nearest 0.001 g/kW-hr.

(3) Round CH_4 to the nearest 0.001 g/kW-hr.

Subpart F—[Amended]

■ 34. Section 1042.501 is amended by revising paragraph (a) to read as follows:

§ 1042.501 How do I run a valid emission test?

(a) Use the equipment and procedures for compression-ignition engines in 40 CFR part 1065 to determine whether Category 1 and Category 2 engines meet the duty-cycle emission standards in § 1042.101(a). Measure the emissions of all exhaust constituents subject to emissions standards as specified in 40 CFR part 1065. Measure CO_2, N_2O, and CH_4 as described in § 1042.235. Use the applicable duty cycles specified in § 1042.505.

* * * * *

Subpart J—[Amended]

■ 35. Section 1042.905 is amended by adding the abbreviations CH_4 and N_2O in alphanumeric order to read as follows:

§ 1042.905 Symbols, acronyms, and abbreviations.

* * * * *

* * * * *

CH_4 methane.

* * * * *

N_2O nitrous oxide.

* * * * *

PART 1045—[AMENDED]

■ 36. The authority citation for part 1045 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart C—[Amended]

■ 37. Section 1045.205 is amended by revising paragraph (q) to read as follows:

§ 1045.205 What must I include in my application?

* * * * *

(q) Report test results as follows:

(1) Report all test results involving measurement of pollutants for which emission standards apply. Include test results from invalid tests or from any other tests, whether or not they were conducted according to the test procedures of subpart F of this part. We may ask you to send other information to confirm that your tests were valid under the requirements of this part and 40 CFR parts 1060 and 1065.

(2) Report measured CO_2, N_2O, and CH_4 as described in § 1045.235. Small-volume engine manufacturers may omit reporting N_2O and CH_4.

* * * * *

■ 38. Section 1045.235 is amended by adding paragraph (g) to read as follows:

§ 1045.235 What emission testing must I perform for my application for a certificate of conformity?

* * * * *

(g) Measure CO_2 and CH_4 with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting in the 2011 and 2012 model years, respectively. Also measure N_2O with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting in the 2013 model year for any engine family that depends on NO_X aftertreatment to meet emission standards. Small-volume engine manufacturers may omit measurement of N_2O and CH_4. These measurements are not required for NTE testing. Use the same units and modal calculations as for your other results to report a single weighted value for each constituent. Round the final values as follows:

(1) Round CO_2 to the nearest 1 g/kW-hr.

(2) Round N_2O to the nearest 0.001 g/kW-hr.

(3) Round CH_4 to the nearest 0.001 g/kW-hr.

Subpart F—[Amended]

■ 39. Section 1045.501 is amended by revising paragraph (b) to read as follows:

§ 1045.501 How do I run a valid emission test?

* * * * *

(b) *General requirements.* Use the equipment and procedures for spark-ignition engines in 40 CFR part 1065 to determine whether engines meet the duty-cycle emission standards in §§ 1045.103 and 1045.105. Measure the emissions of all exhaust constituents subject to emissions standards as specified in 40 CFR part 1065. Measure CO_2, N_2O, and CH_4 as described in § 1045.235. Use the applicable duty cycles specified in § 1045.505. Section 1045.515 describes the supplemental procedures for evaluating whether engines meet the not-to-exceed emission standards in § 1045.107.

* * * * *

PART 1048—[AMENDED]

■ 40. The authority citation for part 1048 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart C—[Amended]

■ 41. Section 1048.205 is amended by revising paragraph (s) to read as follows:

§ 1048.205 What must I include in my application?

* * * * *

(s) Report test results as follows:

(1) Report all test results involving measurement of pollutants for which emission standards apply. Include test results from invalid tests or from any other tests, whether or not they were conducted according to the test procedures of subpart F of this part. We may ask you to send other information to confirm that your tests were valid under the requirements of this part and 40 CFR part 1065.

(2) Report measured CO_2, N_2O, and CH_4 as described in § 1048.235. Small-volume engine manufacturers may omit reporting N_2O and CH_4.

* * * * *

■ 42. Section 1048.235 is amended by adding paragraph (g) to read as follows:

§ 1048.235 What emission testing must I perform for my application for a certificate of conformity?

* * * * *

(g) Measure CO_2 and CH_4 with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting in the 2011 and 2012 model years, respectively. Also measure N_2O with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting in the 2013 model year for any engine family that depends on NOx aftertreatment to meet emission standards. Small-volume engine manufacturers may omit measurement of N_2O and CH_4. These measurements are not required for measurements using field-testing procedures. Use the same units and modal calculations as for your other results to report a single weighted value for each constituent. Round the final values as follows:

(1) Round CO_2 to the nearest 1 g/kW-hr.

(2) Round N_2O to the nearest 0.001 g/kW-hr.

(3) Round CH_4 to the nearest 0.001g/kW-hr.

Subpart F—[Amended]

■ 43. Section 1048.501 is amended by revising paragraph (a) to read as follows:

§ 1048.501 How do I run a valid emission test?

(a) Use the equipment and procedures for spark-ignition engines in 40 CFR part 1065 to determine whether engines meet the duty-cycle emission standards in § 1048.101(a) and (b). Measure the emissions of all the pollutants we regulate in § 1048.101 using the sampling procedures specified in 40 CFR part 1065. Measure CO_2, N_2O, and CH_4 as described in § 1048.235. Use the applicable duty cycles specified in §§ 1048.505 and 1048.510.

* * * * *

Subpart I—[Amended]

■ 44. Section 1048.805 is amended by adding the abbreviations CH_4 and N_2O in alphanumeric order to read as follows:

§ 1048.805 What symbols, acronyms, and abbreviations does this part use?

* * * * *

* * * * *

CH_4 methane.

* * * * *

N_2O nitrous oxide.

* * * * *

PART 1051—[AMENDED]

■ 45. The authority citation for part 1051 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart C—[Amended]

■ 46. Section 1051.205 is amended by revising paragraph (p) to read as follows:

§ 1051.205 What must I include in my application?

* * * * *

(p) Report test results as follows:

(1) Report all test results involving measurement of pollutants for which emission standards apply. Include test results from invalid tests or from any other tests, whether or not they were conducted according to the test procedures of subpart F of this part. We may ask you to send other information to confirm that your tests were valid under the requirements of this part and 40 CFR parts 86 and 1065.

(2) Report measured CO_2, N_2O, and CH_4 as described in § 1051.235. Small-volume manufacturers may omit reporting N_2O and CH_4.

* * * * *

■ 47. Section 1051.235 is amended by adding paragraph (i) to read as follows:

§ 1051.235 What emission testing must I perform for my application for a certificate of conformity?

* * * * *

(i) Measure CO_2 and CH_4 with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting in the 2011 and 2012 model years, respectively. Also measure N_2O with each low-hour certification test using the analytical equipment and procedures specified in 40 CFR part 1065 starting in the 2013 model year for any engine family that depends on NOx aftertreatment to meet emission standards. Small-volume manufacturers may omit measurement of N_2O and CH_4; other manufacturers may provide appropriate data and/or information and omit measurement of N_2O and CH_4 as described in 40 CFR 1065.5. Use the same units and modal calculations as for your other results to report a single weighted value for each constituent. Round the final values as follows:

(1) Round CO_2 to the nearest 1 g/kW-hr or 1 g/km, as appropriate.

(2) Round N_2O to the nearest 0.001 g/kW-hr or 0.001 g/km, as appropriate.

(3) Round CH_4 to the nearest 0.001 g/kW-hr or 0.001 g/km, as appropriate.

Subpart F—[Amended]

■ 48. Section 1051.501 is amended by revising paragraphs (a) and (b) to read as follows:

§ 1051.501 What procedures must I use to test my vehicles or engines?

* * * * *

(a) *Snowmobiles.* For snowmobiles, use the equipment and procedures for spark-ignition engines in 40 CFR part 1065 to determine whether your snowmobiles meet the duty-cycle emission standards in § 1051.103. Measure the emissions of all the pollutants we regulate in § 1051.103. Measure CO_2, N_2O, and CH_4 as described in § 1051.235. Use the duty cycle specified in § 1051.505.

(b) *Motorcycles and ATVs.* For motorcycles and ATVs, use the equipment, procedures, and duty cycle in 40 CFR part 86, subpart F, to determine whether your vehicles meet the exhaust emission standards in § 1051.105 or § 1051.107. Measure the emissions of all the pollutants we regulate in § 1051.105 or § 1051.107. Measure CO_2, N_2O, and CH_4 as described in § 1051.235. If we allow you to certify ATVs based on engine testing, use the equipment, procedures, and duty cycle described or referenced in the section that allows engine testing. For motorcycles with engine displacement at or below 169 cc and all ATVs, use the driving schedule in paragraph (c) of appendix I to 40 CFR part 86. For all other motorcycles, use the driving schedule in paragraph (b) of Appendix I to part 86. With respect to vehicle-speed governors, test motorcycles and ATVs in their ungoverned configuration, unless we approve in advance testing in a governed configuration. We will only approve testing in a governed configuration if you can show that the governor is permanently installed on all production vehicles and is unlikely to be removed in use. With respect to engine-speed governors, test motorcycles and ATVs in their governed configuration. Run the test engine, with all emission-control systems operating, long enough to stabilize emission levels; you may consider emission levels stable without measurement if you accumulate 12 hours of operation.

* * * * *

Subpart I—[Amended]

■ 49. Section 1051.805 is amended by adding the abbreviations CH_4 and N_2O in alphanumeric order to read as follows:

§ 1051.805 What symbols, acronyms, and abbreviations does this part use?

* * * * *

* * * * *

CH_4 methane.

* * * * *

N_2O nitrous oxide.

* * * * *

PART 1054—[AMENDED]

■ 50. The authority citation for part 1054 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart C—[Amended]

■ 51. Section 1054.205 is amended by revising paragraph (p) to read as follows:

§ 1054.205 What must I include in my application?

* * * * *

(p) Report test results as follows:

(1) Report all test results involving measurement of pollutants for which emission standards apply. Include test results from invalid tests or from any other tests, whether or not they were conducted according to the test procedures of subpart F of this part. We may ask you to send other information to confirm that your tests were valid under the requirements of this part and 40 CFR parts 1060 and 1065.

(2) Report measured CO_2, N_2O, and CH_4 as described in § 1054.235. Small-volume engine manufacturers may omit reporting N_2O and CH_4.

* * * * *

■ 52. Section 1054.235 is amended by adding paragraph (g) to read as follows:

§ 1054.235 What exhaust emission testing must I perform for my application for a certificate of conformity?

* * * * *

(g) Measure CO_2 and CH_4 with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting in the 2011 and 2012 model years, respectively. Also measure N_2O with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting in the 2013 model year for any engine family that depends on NOx aftertreatment to meet emission standards. Small-volume engine manufacturers may omit measurement of N_2O and CH_4. Use the same units and modal calculations as for your other results to report a single weighted value for each constituent. Round the final values as follows:

(1) Round CO_2 to the nearest 1 g/kW-hr.

(2) Round N_2O to the nearest 0.001 g/kW-hr.

(3) Round CH_4 to the nearest 0.001 g/kW-hr.

Subpart F—[Amended]

■ 53. Section 1054.501 is amended by revising paragraph (b)(1) to read as follows:

§ 1054.501 How do I run a valid emission test?

* * * * *

(b) * * *

(1) Measure the emissions of all exhaust constituents subject to emissions standards as specified in § 1054.505 and 40 CFR part 1065. Measure CO_2, N_2O, and CH_4 as described in § 1054.235. See § 1054.650 for special provisions that apply for variable-speed engines (including engines shipped without governors).

* * * * *

PART 1065—[AMENDED]

■ 54. The authority citation for part 1065 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart A—[Amended]

■ 55. Section 1065.5 is amended by revising paragraph (a)(3) to read as follows:

§ 1065.5 Overview of this part 1065 and its relationship to the standard-setting part.

(a) * * *

(3) Which exhaust constituents do I need to measure? Measure all exhaust constituents that are subject to emission standards, any other exhaust constituents needed for calculating emission rates, and any additional

exhaust constituents as specified in the standard-setting part. Alternatively, you may omit the measurement of N_2O and CH_4 for an engine, provided it is not subject to an N_2O or CH_4 emission standard. If you omit the measurement of N_2O and CH_4, you must provide other information and/or data that will give us a reasonable basis for estimating the engine's emission rates.

* * * * *

Subpart C—[Amended]

■ 56. The center heading ''NO_x Measurements'' preceding § 1065.270 is revised to read as follows:

NO_X and N_2O Measurements

■ 57. A new § 1065.275 is added under the center heading ''NO_x and N_2O Measurements'' to read as follows:

§ 1065.275 N_2O measurement devices.

(a) *General component requirements.* We recommend that you use an analyzer that meets the specifications in Table 1 of § 1065.205. Note that your system must meet the linearity verification in § 1065.307.

(b) *Instrument types.* You may use any of the following analyzers to measure N_2O:

(1) *Nondispersive infra-red (NDIR) analyzer.* You may use an NDIR analyzer that has compensation algorithms that are functions of other gaseous measurements and the engine's known or assumed fuel properties. The target value for any compensation algorithm is 0.0% (that is, no bias high and no bias low), regardless of the uncompensated signal's bias.

(2) *Fourier transform infra-red (FTIR) analyzer.* You may use an FTIR analyzer that has compensation algorithms that are functions of other gaseous measurements and the engine's known or assumed fuel properties. The target value for any compensation algorithm is 0.0% (that is, no bias high and no bias low), regardless of the uncompensated signal's bias. Use appropriate analytical procedures for interpretation of infrared spectra. For example, EPA Test Method 320 is considered a valid method for spectral interpretation (see *http://www.epa.gov/ttn/emc/methods/method320.html*).

(3) *Photoacoustic analyzer.* You may use a photoacoustic analyzer that has compensation algorithms that are functions of other gaseous measurements. The target value for any compensation algorithm is 0.0% (that is, no bias high and no bias low), regardless of the uncompensated signal's bias. Use an optical wheel configuration that gives analytical priority to measurement of the least stable components in the sample. Select a sample integration time of at least 5 seconds. Take into account sample chamber and sample line volumes when determining flush times for your instrument.

(4) *Gas chromatograph analyzer.* You may use a gas chromatograph with an electron-capture detector (GC–ECD) to measure N_2O concentrations of diluted exhaust for batch sampling.

(i) You may use a packed or porous layer open tubular (PLOT) column phase of suitable polarity and length to achieve adequate resolution of the N_2O peak for analysis. Examples of acceptable columns are a PLOT column consisting of bonded polystyrene-divinylbenzene or a Porapack Q packed column. Take the column temperature profile and carrier gas selection into consideration when setting up your method to achieve adequate N_2O peak resolution.

(ii) Use good engineering judgment to zero your instrument and correct for drift. You do not need to follow the specific procedures in § 1065.530 and § 1065.550(b) that would otherwise apply. For example, you may perform a span gas measurement before and after sample analysis without zeroing. Use the average area counts of the pre-span and post-span measurements to generate a response factor (area counts/span gas concentration), which you then multiply by the area counts from your sample to generate the sample concentration.

(c) *Interference validation.* Perform interference validation for NDIR, FTIR, and photoacoustic analyzers using the procedures of § 1065.375. Interference validation is not required for GC–ECD. Certain interference gases can positively interfere with NDIR, FTIR, and photoacoustic analyzers by causing a response similar to N_2O. When running the interference verification for these analyzers, use interference gases as follows:

(1) The interference gases for NDIR analyzers are CO, CO_2, H_2O, CH_4 and SO_2. Note that interference species, with the exception of H_2O, are dependent on the N_2O infrared absorption band chosen by the instrument manufacturer and should be determined dently for each analyzer.

(2) Use good engineering judgment to determine interference gases for FTIR. Note that interference species, with the exception of H_2O, are dependent on the N_2O infrared absorption band chosen by the instrument manufacturer and should be determined independently for each analyzer.

(3) The interference gases for photoacoustic analyzers are CO, CO_2, and H_2O.

Subpart D—[Amended]

■ 58. Section 1065.303 is revised to read as follows:

§ 1065.303 Summary of required calibration and verifications

The following table summarizes the required and recommended calibrations and verifications described in this subpart and indicates when these have to be performed:

TABLE 1 OF § 1065.303–SUMMARY OF REQUIRED CALIBRATION AND VERIFICATIONS

Type of calibration or verification	Minimum frequency [a]
§ 1065.305: Accuracy, repeatability and noise	Accuracy: Not required, but recommended for initial installation. Repeatability: Not required, but recommended for initial installation. Noise: Not required, but recommended for initial installation.
§ 1065.307: Linearity	Speed: Upon initial installation, within 370 days before testing and after major maintenance. Torque: Upon initial installation, within 370 days before testing and after major maintenance. Electrical power: Upon initial installation, within 370 days before testing and after major maintenance. Clean gas and diluted exhaust flows: Upon initial installation, within 370 days before testing and after major maintenance, unless flow is verified by propane check or by carbon or oxygen balance.

TABLE 1 OF § 1065.303–SUMMARY OF REQUIRED CALIBRATION AND VERIFICATIONS—Continued

Type of calibration or verification	Minimum frequency [a]
	Raw exhaust flow: Upon initial installation, within 185 days before testing and after major maintenance, unless flow is verified by propane check or by carbon or oxygen balance. Gas analyzers: Upon initial installation, within 35 days before testing and after major maintenance. FTIR and photoacoustic analyzers: Upon initial installation, within 370 days before testing and after major maintenance. GC–ECD: Upon initial installation and after major maintenance. PM balance: Upon initial installation, within 370 days before testing and after major maintenance. Stand-alone pressure and temperature: Upon initial installation, within 370 days before testing and after major maintenance.
§ 1065.308: Continuous gas analyzer system response and updating-recording verification—for gas analyzers not continuously compensated for other gas species.	Upon initial installation or after system modification that would effect response.
§ 1065.309: Continuous gas analyzer system-response and updating-recording verification—for gas analyzers continuously compensated for other gas species.	Upon initial installation or after system modification that would effect response.
§ 1065.310: Torque	Upon initial installation and after major maintenance.
§ 1065.315: Pressure, temperature, dewpoint	Upon initial installation and after major maintenance.
§ 1065.320: Fuel flow	Upon initial installation and after major maintenance.
§ 1065.325: Intake flow	Upon initial installation and after major maintenance.
§ 1065.330: Exhaust flow	Upon initial installation and after major maintenance.
§ 1065.340: Diluted exhaust flow (CVS)	Upon initial installation and after major maintenance.
§ 1065.341: CVS and batch sampler verification [b]	Upon initial installation, within 35 days before testing, and after major maintenance.
§ 1065.345: Vacuum leak	Before each laboratory test according to subpart F of this part and before each field test according to subpart J of this part.
§ 1065.350: CO_2 NDIR H_2O interference	Upon initial installation and after major maintenance.
§ 1065.355: CO NDIR CO_2 and H_2O interference	Upon initial installation and after major maintenance.
§ 1065.360: FID calibration, THC FID optimization, and THC FID verification..	Calibrate all FID analyzers: upon initial installation and after major maintenance. Optimize and determine CH_4 response for THC FID analyzers: upon initial installation and after major maintenance. Verify CH_4 response for THC FID analyzers: upon initial installation, within 185 days before testing, and after major maintenance.
§ 1065.362: Raw exhaust FID O_2 interference	For all FID analyzers: upon initial installation, and after major maintenance. For THC FID analyzers: upon initial installation, after major maintenance, and after FID optimization according to § 1065.360.
§ 1065.365: Nonmethane cutter penetration	Upon initial installation, within 185 days before testing, and after major maintenance.
§ 1065.370: CLD CO_2 and H_2O quench	Upon initial installation and after major maintenance.
§ 1065.372: NDUV HC and H_2O interference	Upon initial installation and after major maintenance.
§ 1065.375: N_2O analyzer interference	Upon initial installation and after major maintenance.
§ 1065.376: Chiller NO_2 penetration	Upon initial installation and after major maintenance.
§ 1065.378: NO_2-to-NO converter conversion	Upon initial installation, within 35 days before testing, and after major maintenance.
§ 1065.390: PM balance and weighing	Independent verification: upon initial installation, within 370 days before testing, and after major maintenance. Zero, span, and reference sample verifications: within 12 hours of weighing, and after major maintenance.
§ 1065.395: Inertial PM balance and weighing	Independent verification: upon initial installation, within 370 days before testing, and after major maintenance. Other verifications: upon initial installation and after major maintenance.

[a] Perform calibrations and verifications more frequently, according to measurement system manufacturer instructions and good engineering judgment.

[b] The CVS verification described in § 1065.341 is not required for systems that agree within ± 2% based on a chemical balance of carbon or oxygen of the intake air, fuel, and diluted exhaust.

[b] The CVS verification described in § 1065.341 is not required for systems that agree within ± 2% based on a chemical balance of carbon or oxygen of the intake air, fuel, and diluted exhaust.

■ 59. Section 1065.307 is amended by revising paragraph (c)(6) to read as follows:

§ 1065.307 Linearity verification.

* * * * *

(c) * * *

(6) For all measured quantities, use instrument manufacturer recommendations and good engineering judgment to select reference values, y_{refi}, that cover a range of values that you expect would prevent extrapolation beyond these values during emission testing. We recommend selecting a zero reference signal as one of the reference values of the linearity verification. For stand-alone pressure and temperature linearity verifications and for GC–ECD linearity verifications, we recommend at least three reference values. For all other linearity verifications select at least ten reference values.

* * * * *

■ 60. Section 1065.365 is amended by revising paragraphs (d), (e), and (f) to read as follows:

§ 1065.365 Nonmethane cutter penetration fractions.

* * * * *

(d) *Procedure for a FID calibrated with the NMC.* The method described in this paragraph (d) is recommended over the procedures specified in paragraphs (e) and (f) of this section. If your FID arrangement is such that a FID is always calibrated to measure CH_4 with the NMC, then span that FID with the NMC using a CH_4 span gas, set the product of that FID's CH_4 response factor and CH_4 penetration fraction, $RFPF_{CH4[NMC-FID]}$, equal to 1.0 for all emission calculations, and determine its combined ethane (C_2H_6) response factor and penetration fraction, $RFPF_{C2H6[NMC-FID]}$ as follows:

(1) Select CH_4 and C_2H_6 analytical gas mixtures and ensure that both mixtures meet the specifications of § 1065.750. Select a CH_4 concentration that you would use for spanning the FID during emission testing and select a C_2H_6 concentration that is typical of the peak NMHC concentration expected at the hydrocarbon standard or equal to the THC analyzer's span value.

(2) Start, operate, and optimize the nonmethane cutter according to the manufacturer's instructions, including any temperature optimization.

(3) Confirm that the FID analyzer meets all the specifications of § 1065.360.

(4) Start and operate the FID analyzer according to the manufacturer's instructions.

(5) Zero and span the FID with the nonmethane cutter as you would during emission testing. Span the FID through the cutter by using CH_4 span gas.

(6) Introduce the C_2H_6 analytical gas mixture upstream of the nonmethane cutter. Use good engineering judgment to address the effect of hydrocarbon contamination if your point of introduction is vastly different from the point of zero/span gas introduction.

(7) Allow time for the analyzer response to stabilize. Stabilization time may include time to purge the nonmethane cutter and to account for the analyzer's response.

(8) While the analyzer measures a stable concentration, record 30 seconds of sampled data. Calculate the arithmetic mean of these data points.

(9) Divide the mean C_2H_6 concentration by the reference concentration of C_2H_6, converted to a C_1 basis. The result is the C_2H_6 combined response factor and penetration fraction, $RFPF_{C2H6[NMC-FID]}$. Use this combined response factor and penetration fraction and the product of the CH_4 response factor and CH_4 penetration fraction, $RFPF_{CH4[NMC-FID]}$, set to 1.0 in emission calculations according to § 1065.660(b)(2)(i), § 1065.660(c)(1)(i), or § 1065.665, as applicable.

(e) *Procedure for a FID calibrated with propane, bypassing the NMC.* If you use a single FID for THC and CH_4 determination with an NMC that is calibrated with propane, C_3H_8, by bypassing the NMC, determine its penetration fractions, $PF_{C2H6[NMC-FID]}$ and $PF_{CH4[NMC-FID]}$, as follows:

(1) Select CH_4 and C_2H_6 analytical gas mixtures and ensure that both mixtures meet the specifications of § 1065.750. Select a CH_4 concentration that you would use for spanning the FID during emission testing and select a C_2H_6 concentration that is typical of the peak NMHC concentration expected at the hydrocarbon standard or equal to the THC analyzer's span value.

(2) Start and operate the nonmethane cutter according to the manufacturer's instructions, including any temperature optimization.

(3) Confirm that the FID analyzer meets all the specifications of § 1065.360.

(4) Start and operate the FID analyzer according to the manufacturer's instructions.

(5) Zero and span the FID as you would during emission testing. Span the FID by bypassing the cutter and by using C_3H_8 span gas.

(6) Introduce the C_2H_6 analytical gas mixture upstream of the nonmethane cutter. Use good engineering judgment to address the effect of hydrocarbon contamination if your point of introduction is vastly different from the point of zero/span gas introduction.

(7) Allow time for the analyzer response to stabilize. Stabilization time may include time to purge the nonmethane cutter and to account for the analyzer's response.

(8) While the analyzer measures a stable concentration, record 30 seconds of sampled data. Calculate the arithmetic mean of these data points.

(9) Reroute the flow path to bypass the nonmethane cutter, introduce the C_2H_6 analytical gas mixture, and repeat the steps in paragraph (e)(7) through (e)(8) of this section.

(10) Divide the mean C_2H_6 concentration measured through the nonmethane cutter by the mean C_2H_6 concentration measured after bypassing the nonmethane cutter. The result is the C_2H_6 penetration fraction, $PF_{C2H6[NMC-FID]}$. Use this penetration fraction according to § 1065.660(b)(2)(ii), § 1065.660(c)(1)(ii), or § 1065.665, as applicable.

(11) Repeat the steps in paragraphs (e)(6) through (e)(10) of this section, but with the CH_4 analytical gas mixture instead of C_2H_6. The result will be the CH_4 penetration fraction, $PF_{CH4[NMC-FID]}$. Use this penetration fraction according to § 1065.660(b)(2)(ii), § 1065.660(c)(1)(ii), or § 1065.665, as applicable.

(f) *Procedure for a FID calibrated with methane, bypassing the NMC.* If you use a FID with an NMC that is calibrated with methane, CH_4, by bypassing the NMC, determine its combined ethane (C_2H_6) response factor and penetration fraction, $RFPF_{C2H6[NMC-FID]}$, as well as its CH_4 penetration fraction, $PF_{CH4[NMC-FID]}$, as follows:

(1) Select CH_4 and C_2H_6 analytical gas mixtures and ensure that both mixtures meet the specifications of § 1065.750. Select a CH_4 concentration that you would use for spanning the FID during emission testing and select a C_2H_6 concentration that is typical of the peak NMHC concentration expected at the hydrocarbon standard or equal to the THC analyzer's span value.

(2) Start and operate the nonmethane cutter according to the manufacturer's instructions, including any temperature optimization.

(3) Confirm that the FID analyzer meets all the specifications of § 1065.360.

(4) Start and operate the FID analyzer according to the manufacturer's instructions.

(5) Zero and span the FID as you would during emission testing. Span the FID by bypassing the cutter and by using CH_4 span gas. Note that you must span the FID on a C_1 basis. For example, if your span gas has a methane reference value of 100 µmol/mol, the correct FID response to that span gas is 100 µmol/mol because there is one carbon atom per CH_4 molecule.

(6) Introduce the C_2H_6 analytical gas mixture upstream of the nonmethane cutter. Use good engineering judgment to address the effect of hydrocarbon contamination if your point of introduction is vastly different from the point of zero/span gas introduction.

(7) Allow time for the analyzer response to stabilize. Stabilization time may include time to purge the nonmethane cutter and to account for the analyzer's response.

(8) While the analyzer measures a stable concentration, record 30 seconds of sampled data. Calculate the arithmetic mean of these data points.

(9) Divide the mean C_2H_6 concentration by the reference concentration of C_2H_6, converted to a C_1 basis. The result is the C_2H_6 combined response factor and penetration fraction, $RFPF_{C2H6[NMC-FID]}$. Use this combined response factor and penetration fraction according to § 1065.660(b)(2)(iii),

§ 1065.660(c)(1)(iii), or § 1065.665, as applicable.

(10) Introduce the CH_4 analytical gas mixture upstream of the nonmethane cutter. Use good engineering judgment to address the effect of hydrocarbon contamination if your point of introduction is vastly different from the point of zero/span gas introduction.

(11) Allow time for the analyzer response to stabilize. Stabilization time may include time to purge the nonmethane cutter and to account for the analyzer's response.

(12) While the analyzer measures a stable concentration, record 30 seconds of sampled data. Calculate the arithmetic mean of these data points.

(13) Reroute the flow path to bypass the nonmethane cutter, introduce the CH_4 analytical gas mixture, and repeat the steps in paragraphs (e)(11) and (12) of this section.

(14) Divide the mean CH_4 concentration measured through the nonmethane cutter by the mean CH_4 concentration measured after bypassing the nonmethane cutter. The result is the CH_4 penetration fraction, $PF_{CH4[NMC-FID]}$. Use this penetration fraction according to § 1065.660(b)(2)(iii), § 1065.660(c)(1)(iii), or § 1065.665, as applicable.

■ 61. The center heading ''NO_X MEASUREMENTS'' preceding § 1065.370 is revised to read as follows:

NO_X and N_2O Measurements

■ 62. A new § 1065.375 is added under the center header ''NO_X and N_2O Measurements'' to read as follows:

§ 1065.375 Interference verification for N_2O analyzers.

(a) *Scope and frequency.* See § 1065.275 to determine whether you need to verify the amount of interference after initial analyzer installation and after major maintenance.

(b) *Measurement principles.* Interference gasses can positively interfere with certain analyzers by causing a response similar to N_2O. If the analyzer uses compensation algorithms that utilize measurements of other gases to meet this interference verification, simultaneously conduct these other measurements to test the compensation algorithms during the analyzer interference verification.

(c) *System requirements.* Analyzers must have combined interference that is within (0.0 ± 1.0) µmol/mol. We strongly recommend a lower interference that is within (0.0 ± 0.5) µmol/mol.

(d) *Procedure.* Perform the interference verification as follows:

(1) Start, operate, zero, and span the N_2O analyzer as you would before an emission test. If the sample is passed through a dryer during emission testing, you may run this verification test with the dryer if it meets the requirements of § 1065.342. Operate the dryer at the same conditions as you will for an emission test. You may also run this verification test without the sample dryer.

(2) Create a humidified test gas by bubbling a multi component span gas that incorporates the target interference species and meets the specifications in § 1065.750 through distilled water in a sealed vessel. If the sample is not passed through a dryer during emission testing, control the vessel temperature to generate an H_2O level at least as high as the maximum expected during emission testing. If the sample is passed through a dryer during emission testing, control the vessel temperature to generate an H_2O level at least as high as the level determined in § 1065.145(e)(2) for that dryer. Use interference span gas concentrations that are at least as high as the maximum expected during testing.

(3) Introduce the humidified interference test gas into the sample system. You may introduce it downstream of any sample dryer, if one is used during testing.

(4) If the sample is not passed through a dryer during this verification test, measure the water mole fraction, x_{H2O}, of the humidified interference test gas as close as possible to the inlet of the analyzer. For example, measure dewpoint, T_{dew}, and absolute pressure, p_{total}, to calculate x_{H2O}. Verify that the water content meets the requirement in paragraph (d)(2) of this section. If the sample is passed through a dryer during this verification test, you must verify that the water content of the humidified test gas downstream of the vessel meets the requirement in paragraph (d)(2) of this section based on either direct measurement of the water content (e.g., dewpoint and pressure) or an estimate based on the vessel pressure and temperature. Use good engineering judgment to estimate the water content. For example, you may use previous direct measurements of water content to verify the vessel's level of saturation.

(5) If a sample dryer is not used in this verification test, use good engineering judgment to prevent condensation in the transfer lines, fittings, or valves from the point where x_{H2O} is measured to the analyzer. We recommend that you design your system so that the wall temperatures in the transfer lines, fittings, and valves from the point where x_{H2O} is measured to the analyzer are at least 5 °C above the local sample gas dewpoint.

(6) Allow time for the analyzer response to stabilize. Stabilization time may include time to purge the transfer line and to account for analyzer response.

(7) While the analyzer measures the sample's concentration, record its output for 30 seconds. Calculate the arithmetic mean of this data.

(8) The analyzer meets the interference verification if the result of paragraph (d)(7) of this section meets the tolerance in paragraph (c) of this section.

(9) You may also run interference procedures separately for individual interference gases. If the interference gas levels used are higher than the maximum levels expected during testing, you may scale down each observed interference value by multiplying the observed interference by the ratio of the maximum expected concentration value to the actual value used during this procedure. You may run separate interference concentrations of H_2O (down to 0.025 mol/mol H_2O content) that are lower than the maximum levels expected during testing, but you must scale up the observed H_2O interference by multiplying the observed interference by the ratio of the maximum expected H_2O concentration value to the actual value used during this procedure. The sum of the scaled interference values must meet the tolerance specified in paragraph (c) of this section.

Subpart F—[Amended]

■ 63. Section 1065.550 is amended by revising paragraphs (b) introductory text and (b)(1), adding and reserving paragraph (b)(3), and adding paragraph (b)(4) to read as follows:

§ 1065.550 Gas analyzer range validation, drift validation, and drift correction.

* * * * *

(b) *Drift validation and drift correction.* Calculate two sets of brake-specific emission results for each test interval. Calculate one set using the data before drift correction and calculate the other set after correcting all the data for drift according to § 1065.672. Use the two sets of brake-specific emission results to validate the duty cycle for drift as follows:

(1) The duty cycle is validated for drift if you satisfy one of the following criteria:

(i) For each test interval of the duty cycle and for each measured exhaust constituent, the difference between the uncorrected and the corrected brake-specific emission values over the test interval is within ±4% of the uncorrected value or applicable emission standard, whichever is greater. This requirement also applies for CO_2, whether or not an emission standard applies for CO_2. Where no emission standard applies for CO_2, the difference must be within ±4% of the uncorrected value. See paragraph (b)(4) of this section for exhaust constituents other than CO_2 for which no emission standard applies.

(ii) For the entire duty cycle and for each regulated pollutant, the difference between the uncorrected and corrected composite brake-specific emission values over the entire duty cycle is within ±4% of the uncorrected value or the applicable emission standard, whichever is greater. Note that for purposes of drift validation using composite brake-specific emission values over the entire duty cycle, leave unaltered any negative emission results over a given test interval (i.e., do not set them to zero). A third calculation of composite brake-specific emission values is required for final reporting. This calculation uses drift-corrected mass (or mass rate) values from each test interval and sets any negative mass (or mass rate) values to zero before calculating the composite brake-specific emission values over the entire duty cycle. This requirement also applies for CO_2, whether or not an emission standard applies for CO_2. Where no emission standard applies for CO_2, the difference must be within ±4% of the uncorrected value. See paragraph (b)(3) of this section for exhaust constituents other than CO_2 for which no emission standard applies.

* * * * *

(3) [Reserved]

(4) The provisions of paragraph (b)(3) of this section apply for measurement of pollutants other than CO_2 for which no emission standard applies. You may use measurements that do not meet the drift validation criteria specified in paragraph (b)(1) of this section. For example, this allowance may be appropriate for measuring and reporting very low concentrations of CH_4 and N_2O as long as no emission standard applies for these compounds.

Subpart G—[Amended]

■ 64. Section 1065.601 is amended by revising paragraph (a)(1) to read as follows:

§ 1065.601 Overview.

(a) * * *

(1) Use the signals recorded before, during, and after an emission test to calculate brake-specific emissions of each measured exhaust constituent.

* * * * *

■ 65. Section 1065.660 is amended by revising paragraphs (a), (b) introductory text, (b)(1), (b)(2), and (b)(3) introductory text, and adding paragraph (c) to read as follows:

§ 1065.660 THC, NMHC, and CH_4 determination.

(a) *THC determination and THC/CH_4 initial contamination corrections.* (1) If we require you to determine THC emissions, calculate $x_{THC[THC-FID]cor}$ using the initial THC contamination concentration $x_{THC[THC-FID]init}$ from § 1065.520 as follows:

$$x_{THC[THC\text{-}FID]cor} = x_{THC[THC\text{-}FID]uncor} - x_{THC[THC\text{-}FID]\,init} \qquad \text{Eq. 1065.660-1}$$

Example:

$x_{THCuncor}$ = 150.3 μmol/mol

$x_{THCinit}$ = 1.1 μmol/mol

x_{THCcor} = 150.3 − 1.1

x_{THCcor} = 149.2 μmol/mol

(2) For the NMHC determination described in paragraph (b) of this section, correct $x_{THC[THC-FID]}$ for initial HC contamination using Eq. 1065.660–1. You may correct $x_{THC[NMC-FID]}$ for initial contamination of the CH_4 sample train using Eq. 1065.660–1, substituting in CH_4 concentrations for THC.

(3) For the CH_4 determination described in paragraph (c) of this section, you may correct $x_{THC[NMC-FID]}$ for initial contamination of the CH_4 sample train using Eq. 1065.660–1, substituting in CH_4 concentrations for THC.

(b) *NMHC determination.* Use one of the following to determine NMHC concentration, x_{NMHC}:

(1) If you do not measure CH_4, you may determine NMHC concentrations as described in § 1065.650(c)(1)(vi).

(2) For nonmethane cutters, calculate x_{NMHC} using the nonmethane cutter's penetration fractions (PF) of CH_4 and C_2H_6 from § 1065.365, and using the HC contamination and dry-to-wet corrected THC concentration $x_{THC[THC-FID]cor}$ as determined in paragraph (a) of this section.

(i) Use the following equation for penetration fractions determined using an NMC configuration as outlined in § 1065.365(d):

$$x_{NMHC} = \frac{x_{THC[THC\text{-}FID]cor} - x_{THC[NMC\text{-}FID]cor} \cdot RF_{CH4[THC\text{-}FID]}}{1 - RFPF_{C2H6[NMC\text{-}FID]} \cdot RF_{CH4[THC\text{-}FID]}} \qquad \text{Eq. 1065.660-2}$$

Where:

x_{NMHC} = concentration of NMHC.

$x_{THC[THC-FID]cor}$ = concentration of THC, HC contamination and dry-to-wet corrected, as measured by the THC FID during sampling while bypassing the NMC.

$x_{THC[NMC-FID]cor}$ = concentration of THC, HC contamination (optional) and dry-to-wet corrected, as measured by the NMC FID during sampling through the NMC.

$RF_{CH4[THC-FID]}$ = response factor of THC FID to CH_4, according to § 1065.360(d).

$RFPF_{C2H6[NMC-FID]}$ = nonmethane cutter combined ethane response factor and penetration fraction, according to § 1065.365(d).

Example:

$x_{THC[THC-FID]cor}$ = 150.3 μmol/mol

$x_{THC[NMC-FID]cor}$ = 20.5 μmol/mol

$RFPF_{C2H6[NMC-FID]}$ = 0.019

$RF_{CH4[THC-FID]}$ = 1.05

$$x_{NMHC} = \frac{150.3 - 20.5 \cdot 1.05}{1 - 0.019 \cdot 1.05}$$

x_{NMHC} = 131.4 μmol/mol

(ii) For penetration fractions determined using an NMC configuration as outlined in section § 1065.365(e), use the following equation:

$$x_{\mathrm{NMHC}} = \frac{x_{\mathrm{THC[THC\text{-}FID]cor}} \cdot PF_{\mathrm{CH4[NMC\text{-}FID]cor}} - x_{\mathrm{THC[NMC\text{-}FID]}}}{PF_{\mathrm{CH4[NMC\text{-}FID]}} - PF_{\mathrm{C2H6[NMC\text{-}FID]}}} \quad \text{Eq. 1065.660-3}$$

Where:

x_{NMHC} = concentration of NMHC.

$x_{\mathrm{THC[THC-FID]cor}}$ = concentration of THC, HC contamination and dry-to-wet corrected, as measured by the THC FID during sampling while bypassing the NMC.

$PF_{\mathrm{CH4[NMC-FID]}}$ = nonmethane cutter CH_4 penetration fraction, according to § 1065.365(e).

$x_{\mathrm{THC[NMC-FID]cor}}$ = concentration of THC, HC contamination (optional) and dry-to-wet corrected, as measured by the THC FID during sampling through the NMC.

$PF_{\mathrm{C2H6[NMC-FID]}}$ = nonmethane cutter ethane penetration fraction, according to § 1065.365(e).

Example:

$x_{\mathrm{THC[THC-FID]cor}}$ = 150.3 μmol/mol

$PF_{\mathrm{CH4[NMC-FID]}}$ = 0.990

$x_{\mathrm{THC[NMC-FID]cor}}$ = 20.5 μmol/mol

$PF_{\mathrm{C2H6[NMC-FID]}}$ = 0.020

$$x_{\mathrm{NMHC}} = \frac{150.3 \cdot 0.990 - 20.5}{0.990 - 0.020}$$

x_{NMHC} = 132.3 μmol/mol

(iii) For penetration fractions determined using an NMC configuration as outlined in § 1065.365(f), use the following equation:

$$x_{\mathrm{NMHC}} = \frac{x_{\mathrm{THC[THC\text{-}FID]cor}} \cdot PF_{\mathrm{CH4[NMC\text{-}FID]}} - x_{\mathrm{THC[NMC\text{-}FID]cor}} \cdot RF_{\mathrm{CH4[THC\text{-}FID]}}}{PF_{\mathrm{CH4[NMC\text{-}FID]}} - RFPF_{\mathrm{C2H6[NMC\text{-}FID]}} \cdot RF_{\mathrm{CH4[THC\text{-}FID]}}} \quad \text{Eq. 1065.660-4}$$

Where:

x_{NMHC} = concentration of NMHC.

$x_{\mathrm{THC[THC-FID]cor}}$ = concentration of THC, HC contamination and dry-to-wet corrected, as measured by the THC FID during sampling while bypassing the NMC.

$PF_{\mathrm{CH4[NMC-FID]}}$ = nonmethane cutter CH_4 penetration fraction, according to § 1065.365(f).

$x_{\mathrm{THC[NMC-FID]cor}}$ = concentration of THC, HC contamination (optional) and dry-to-wet corrected, as measured by the THC FID during sampling through the NMC.

$RFPF_{\mathrm{C2H6[NMC-FID]}}$ = nonmethane cutter CH_4 combined ethane response factor and penetration fraction, according to § 1065.365(f).

$RF_{\mathrm{CH4[THC-FID]}}$ = response factor of THC FID to CH_4, according to § 1065.360(d).

Example:

$x_{\mathrm{THC[THC-FID]cor}}$ = 150.3 μmol/mol

$PF_{\mathrm{CH4[NMC-FID]}}$ = 0.990

$x_{\mathrm{THC[NMC-FID]cor}}$ = 20.5 μmol/mol

$RFPF_{\mathrm{C2H6[NMC-FID]}}$ = 0.019

$RF_{\mathrm{CH4[THC-FID]}}$ = 0.980

$$x_{\mathrm{NMHC}} = \frac{150.3 \cdot 0.990 - 20.5 \cdot 0.980}{0.990 - 0.019 \cdot 0.980}$$

x_{NMHC} = 132.5 μmol/mol

(3) For a gas chromatograph, calculate x_{NMHC} using the THC analyzer's response factor (RF) for CH_4, from § 1065.360, and the HC contamination and dry-to-wet corrected initial THC concentration $x_{\mathrm{THC[THC-FID]cor}}$ as determined in paragraph (a) of this section as follows:

* * * * *

(c) *CH_4 determination.* Use one of the following methods to determine CH_4 concentration, x_{CH4}:

(1) For nonmethane cutters, calculate x_{CH4} using the nonmethane cutter's penetration fractions (*PF*) of CH_4 and C_2H_6 from § 1065.365, using the dry-to-wet corrected CH_4 concentration $x_{\mathrm{THC[NMC-FID]cor}}$ as determined in paragraph (a) of this section and optionally using the CH_4 contamination correction under paragraph (a) of this section.

(i) Use the following equation for penetration fractions determined using an NMC configuration as outlined in § 1065.365(d):

$$x_{\mathrm{CH4}} = \frac{x_{\mathrm{THC[NMC\text{-}FID]cor}} - x_{\mathrm{THC[THC\text{-}FID]cor}} \cdot RFPF_{\mathrm{C2H6[NMC\text{-}FID]}}}{1 - RFPF_{\mathrm{C2H6[NMC\text{-}FID]}} \cdot RF_{\mathrm{CH4[THC\text{-}FID]}}} \quad \text{Eq. 1065.660-6}$$

Where:

x_{CH4} = concentration of CH_4.

$x_{\mathrm{THC[NMC-FID]cor}}$ = concentration of THC, HC contamination (optional) and dry-to-wet corrected, as measured by the NMC FID during sampling through the NMC.

$x_{\mathrm{THC[THC-FID]cor}}$ = concentration of THC, HC contamination and dry-to-wet corrected, as measured by the THC FID during sampling while bypassing the NMC.

$RFPF_{\mathrm{C2H6[NMC-FID]}}$ = the combined ethane response factor and penetration fraction of the nonmethane cutter, according to § 1065.365(d).

$RF_{\mathrm{CH4[THC-FID]}}$ = response factor of THC FID to CH_4, according to § 1065.360(d).

Example:

$x_{\mathrm{THC[NMC-FID]cor}}$ = 10.4 μmol/mol

$x_{\mathrm{THC[THC-FID]cor}}$ = 150.3 μmol/mol

$RFPF_{\mathrm{C2H6[NMC-FID]}}$ = 0.019

$RF_{\mathrm{CH4[THC-FID]}}$ = 1.05

$$x_{\mathrm{CH4}} = \frac{10.4 - 150.3 \cdot 0.019}{1 - 0.019 \cdot 1.05}$$

x_{CH4} = 7.69 μmol/mol

(ii) For penetration fractions determined using an NMC configuration as outlined in § 1065.365(e), use the following equation:

$$x_{\mathrm{CH4}} = \frac{x_{\mathrm{THC[NMC\text{-}FID]cor}} - x_{\mathrm{THC[THC\text{-}FID]cor}} \cdot PF_{\mathrm{C2H6[NMC\text{-}FID]}}}{RF_{\mathrm{CH4[THC\text{-}FID]}} \cdot \left(PF_{\mathrm{CH4[NMC\text{-}FID]}} - PF_{\mathrm{C2H6[NMC\text{-}FID]}}\right)} \quad \text{Eq. 1065.660-7}$$

Where:

x_{CH4} = concentration of CH_4.

$x_{\mathrm{THC[NMC-FID]cor}}$ = concentration of THC, HC contamination (optional) and dry-to-wet corrected, as measured by the NMC FID during sampling through the NMC.

$x_{\mathrm{THC[THC-FID]cor}}$ = concentration of THC, HC contamination and dry-to-wet corrected, as measured by the THC FID during sampling while bypassing the NMC.

$PF_{\mathrm{C2H6[NMC-FID]}}$ = nonmethane cutter ethane penetration fraction, according to § 1065.365(e).

$RF_{\mathrm{CH4[THC-FID]}}$ = response factor of THC FID to CH_4, according to § 1065.360(d).

$PF_{\mathrm{CH4[NMC-FID]}}$ = nonmethane cutter CH_4 penetration fraction, according to § 1065.365(e).

Example:

$x_{\mathrm{THC[NMC-FID]cor}}$ = 10.4 μmol/mol

$x_{\mathrm{THC[THC-FID]cor}}$ = 150.3 μmol/mol

$PF_{\mathrm{C2H6[NMC-FID]}}$ = 0.020

$RF_{\mathrm{CH4[THC-FID]}}$ = 1.05

$PF_{CH4[NMC-FID]}$ = 0.990

$$x_{CH4} = \frac{10.4 - 150.3 \cdot 0.020}{1.05 \cdot (0.990 - 0.020)}$$

x_{CH4} = 7.25 µmol/mol

(iii) For penetration fractions determined using an NMC configuration as outlined in § 1065.365(f), use the following equation:

$$x_{CH4} = \frac{x_{THC[NMC\text{-}FID]cor} - x_{THC[THC\text{-}FID]cor} \cdot RFPF_{C2H6[NMC\text{-}FID]}}{PF_{CH4[NMC\text{-}FID]} - RFPF_{C2H6[NMC\text{-}FID]} \cdot RF_{CH4[THC\text{-}FID]}} \quad \text{Eq. 1065.660-8}$$

Where:

x_{CH4} = concentration of CH_4.

$x_{THC[NMC-FID]cor}$ = concentration of THC, HC contamination (optional) and dry-to-wet corrected, as measured by the NMC FID during sampling through the NMC.

$x_{THC[THC-FID]cor}$ = concentration of THC, HC contamination and dry-to-wet corrected, as measured by the THC FID during sampling while bypassing the NMC.

$RFPF_{C2H6[NMC-FID]}$ = the combined ethane response factor and penetration fraction of the nonmethane cutter, according to § 1065.365(f).

$PF_{CH4[NMC-FID]}$ = nonmethane cutter CH_4 penetration fraction, according to § 1065.365(f).

$RF_{CH4[THC-FID]}$ = response factor of THC FID to CH_4, according to § 1065.360(d).

Example:

$x_{THC[NMC-FID]cor}$ = 10.4 µmol/mol

$x_{THC[THC-FID]cor}$ = 150.3 µmol/mol

$RFPF_{C2H6[NMC-FID]}$ = 0.019

$PF_{CH4[NMC-FID]}$ = 0.990

$RF_{CH4[THC-FID]}$ = 1.05

$$x_{CH4} = \frac{10.4 - 150.3 \cdot 0.019}{0.990 - 0.019 \cdot 1.05}$$

x_{CH4} = 7.78 µmol/mol

(2) For a gas chromatograph, x_{CH4} is the actual dry-to-wet corrected CH_4 concentration as measured by the analyzer.

Subpart H—[Amended]

■ 66. Section 1065.750 is amended by revising paragraph (a)(1)(ii) and adding paragraph (a)(3)(xi) to read as follows:

§ 1065.750 Analytical Gases.

* * * * *

(a) * * *

(1) * * *

(ii) Contamination as specified in the following table:

TABLE 1 OF § 1065.750—GENERAL SPECIFICATIONS FOR PURIFIED GASES.

Constituent	Purified synthetic air [1]	Purified N_2 [1]
THC (C_1 equivalent)	≤ 0.05 µmol/mol	≤ 0.05 µmol/mol.
CO	≤ 1 µmol/mol	≤ 1 µmol/mol.
CO_2	≤ 10 µmol/mol	≤ 10 µmol/mol.
O_2	0.205 to 0.215 mol/mol	≤ 2 µmol/mol.
NO_X	≤ 0.02 µmol/mol	≤ 0.02 µmol/mol.
N_2O [2]	≤ 0.05 µmol/mol	≤ 0.05 µmol/mol.

[1] We do not require these levels of purity to be NIST-traceable.

[2] The N_2O limit applies only if the standard-setting part requires you to report N_2O.

* * * * *

(3) * * *

(xi) N_2O, balance purified synthetic air.

* * * * *

■ 67. Section 1065.1001 is amended by revising the definition for ''Oxides of nitrogen'' to read as follows:

§ 1065.1001 Definitions.

* * * * *

Oxides of nitrogen means NO and NO_2 as measured by the procedures specified in § 1065.270. Oxides of nitrogen are expressed quantitatively as if the NO is in the form of NO_2, such that you use an effective molar mass for all oxides of nitrogen equivalent to that of NO_2.

* * * * *

■ 68. Section 1065.1005 is amended by revising paragraphs (b), (f)(2), and (g) to read as follows:

§ 1065.1005 Symbols, abbreviations, acronyms, and units of measure.

* * * * *

(b) *Symbols for chemical species.* This part uses the following symbols for chemical species and exhaust constituents:

Symbol	Species
Ar	argon.
C	carbon.
CH_4	methane.
C_2H_6	ethane.
C_3H_8	propane.
C_4H_{10}	butane.
C_5H_{12}	pentane.
CO	carbon monoxide.
CO_2	carbon dioxide.
H	atomic hydrogen.
H_2	molecular hydrogen.
H_2O	water.
He	helium.
^{85}Kr	krypton 85.
N_2	molecular nitrogen.
NMHC	nonmethane hydrocarbon.
NMHCE	nonmethane hydrocarbon equivalent.
NO	nitric oxide.
NO_2	nitrogen dioxide.
NO_X	oxides of nitrogen.
N_2O	nitrous oxide.
NOTHC	nonoxygenated hydrocarbon.
O_2	molecular oxygen.
OHC	oxygenated hydrocarbon.
^{210}Po	polonium 210.
PM	particulate mass.
S	sulfur.
SO_2	sulfur dioxide.
THC	total hydrocarbon.
ZrO_2	zirconium dioxide.

* * * * *

(f) * * *

(2) This part uses the following molar masses or effective molar masses of chemical species:

Symbol	Quantity	g/mol (10^{-3}·kg·mol^{-1})
M_{air}	molar mass of dry air	28.96559
M_{Ar}	molar mass of argon	39.948
M_{C}	molar mass of carbon	12.0107
M_{CO}	molar mass of carbon monoxide	28.0101
M_{CO2}	molar mass of carbon dioxide	44.0095
M_{H}	molar mass of atomic hydrogen	1.00794
M_{H2}	molar mass of molecular hydrogen	2.01588
M_{H2O}	molar mass of water	18.01528
M_{He}	molar mass of helium	4.002602
M_{N}	molar mass of atomic nitrogen	14.0067
M_{N2}	molar mass of molecular nitrogen	28.0134
M_{NMHC}	effective molar mass of nonmethane hydrocarbon [2]	13.875389
M_{NMHCE}	effective molar mass of nonmethane equivalent hydrocarbon [2]	13.875389
M_{NOx}	effective molar mass of oxides of nitrogen [3]	46.0055
M_{N2O}	effective molar mass of nitrous oxide	44.0128
M_{O}	molar mass of atomic oxygen	15.9994
M_{O2}	molar mass of molecular oxygen	31.9988
M_{C3H8}	molar mass of propane	44.09562
M_{S}	molar mass of sulfur	32.065
M_{THC}	effective molar mass of total hydrocarbon [2]	13.875389
M_{THCE}	effective molar mass of total hydrocarbon equivalent [2]	13.875389

[1] See paragraph (f)(1) of this section for the composition of dry air
[2] The effective molar masses of THC, THCE, NMHC, and NMHCE are defined by an atomic hydrogen-to-carbon ratio, α, of 1.85
[3] The effective molar mass of NOx is defined by the molar mass of nitrogen dioxide, NO_2

* * * * *

(g) *Other acronyms and abbreviations.* This part uses the following additional abbreviations and acronyms:

ASTM American Society for Testing and Materials.
BMD bag mini-diluter.
BSFC brake-specific fuel consumption.
CARB California Air Resources Board.
CFR Code of Federal Regulations.
CFV critical-flow venturi.
CI compression-ignition.
CITT Curb Idle Transmission Torque.
CLD chemiluminescent detector.
CVS constant-volume sampler.
DF deterioration factor.
ECM electronic control module.
EFC electronic flow control.
EGR exhaust gas recirculation.
EPA Environmental Protection Agency.
FEL Family Emission Limit
FID flame-ionization detector.
GC gas chromatograph.
GC–ECD gas chromatograph with an electron-capture detector.
IBP initial boiling point.
ISO International Organization for Standardization.
LPG liquefied petroleum gas.
NDIR nondispersive infrared.
NDUV nondispersive ultraviolet.
NIST National Institute for Standards and Technology.
PDP positive-displacement pump.
PEMS portable emission measurement system.
PFD partial-flow dilution.
PMP Polymethylpentene.
pt. a single point at the mean value expected at the standard.
PTFE polytetrafluoroethylene (commonly known as Teflon™).
RE rounding error.
RMC ramped-modal cycle.
RMS root-mean square.
RTD resistive temperature detector.
SSV subsonic venturi.
SI spark-ignition.
UCL upper confidence limit.
UFM ultrasonic flow meter.
U.S.C. United States Code.

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H.R. 2892/P.L. 111–83
Department of Homeland Security Appropriations Act, 2010 (Oct. 28, 2009; 123 Stat. 2142)

H.R. 2647/P.L. 111–84
National Defense Authorization Act for Fiscal Year 2010 (Oct. 28, 2009; 123 Stat. 2190)

H.R. 3183/P.L. 111–85
Energy and Water Development and Related Agencies Appropriations Act, 2010 (Oct. 28, 2009; 123 Stat. 2845)

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