Federal Register

5–26–09
Vol. 74 No. 99
Tuesday
May 26, 2009

Pages 24695–25144

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WHEN: Tuesday, June 9, 2009
9:00 a.m.–12:30 p.m.

WHERE: Office of the Federal Register
Conference Room, Suite 700
800 North Capitol Street, NW.
Washington, DC 20002

RESERVATIONS: (202) 741-6008

Printed on recycled paper.

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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. 99

Tuesday, May 26, 2009

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Parts 91 and 135

[Docket No. FAA–2002–14002; Amendment Nos. 91–306 and 135–110]

RIN 2120–AJ46

Communication and Area Navigation Equipment (RNAV) Operations in Remote Locations and Mountainous Terrain

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule; correction.

SUMMARY: This document corrects the amendment number in the final rule published in the **Federal Register** on Friday, May 1, 2009. That final rule amends the regulations to allow the use of the published Obstacle Departure Procedures (ODP) or an alternative procedure or route assigned by Air Traffic Control (ATC). Also, that final rule amends the requirements to facilitate compliance and accurately reflect operating conditions in areas in which the terrain impedes communications.

DATES: This amendment becomes effective June 30, 2009.

FOR FURTHER INFORMATION CONTACT: For technical questions concerning this final rule, contact Dennis Mills, Aviation Safety Inspector, Air Transportation Division, Fight Standards Service, AFS–220, Federal Aviation Administration, 800 Independence Avenue, SW., Washington, DC 20591; telephone (202) 493–4901 facsimile (202) 267–5229, e-mail *dennis.mills@faa.gov.* For legal questions concerning this final rule, contact Robert Hawks, General Attorney, Office of the Chief Counsel, Regulations Division, AGC–240, Federal Aviation Administration, 800 Independence Avenue, SW., Washington, DC 20591; telephone (202) 267–7143, facsimile (202) 267–7971, e-mail *rob.hawks@faa.gov.*

Correction: In the final rule, published in the **Federal Register** issue of Friday, May 1, 2009 (74 FR 20202), make the following correction—On page 20202, in the second column, the fifth line of the heading, ''Amendment Nos. 91–306 and 135–110'' is corrected to read ''Amendment Nos. 91–306 and 135–116.''

Issued in Washington, DC, on May 19, 2009.

Pamela Hamilton-Powell,

Director, Office of Rulemaking.

[FR Doc. E9–12063 Filed 5–22–09; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF DEFENSE

Department of the Navy

32 CFR Part 706

Certifications and Exemptions Under the International Regulations for Preventing Collisions at Sea, 1972

AGENCY: Department of the Navy, DoD.

ACTION: Final rule.

SUMMARY: The Department of the Navy is amending its certifications and exemptions under the International Regulations for Preventing Collisions at Sea, 1972 (72 COLREGS), to reflect that the Deputy Assistant Judge Advocate General (Admiralty and Maritime Law) of the Navy has determined that *USS Carl Vinson* (CVN 70) is a vessel of the Navy which, due to its special construction and purpose, cannot comply fully with certain provisions of the 72 COLREGS without interfering with its special function as a naval ship. The intended effect of this rule is to warn mariners in waters where 72 COLREGS apply.

DATES: This rule is effective May 26, 2009 and is applicable beginning May 14, 2009.

FOR FURTHER INFORMATION CONTACT: Commander M. Robb Hyde, JAGC, U.S. Navy, Deputy Assistant Judge Advocate General (Admiralty and Maritime Law), Office of the Judge Advocate General, Department of the Navy, 1322 Patterson Ave., SE., Suite 3000, Washington Navy Yard, DC 20374–5066, telephone number: 202–685–5040.

SUPPLEMENTARY INFORMATION: Pursuant to the authority granted in 33 U.S.C. 1605, the Department of the Navy amends 32 CFR part 706.

The Secretary of the Navy previously certified that *USS Carl Vinson* (CVN 70) is a vessel of the Navy which, due to its special construction and purpose, cannot fully comply with 72 COLREGS. This amendment provides notice that the Deputy Assistant Judge Advocate General (Admiralty and Maritime Law) of the Navy, under authority delegated by the Secretary of the Navy, has amended that certification to reflect that the forward and aft anchor lights on *USS Carl Vinson* (CVN 70), previously certified as not in compliance with 72 COLREGS, now comply with the applicable 72 COLREGS requirements, to wit: The two forward and the two aft anchor lights located below the flight deck were removed and replaced by one single forward and one single aft anchor light above the hull and near ship's fore-aft centerline, as required by Rules 21(a), 21(e), 30(a)(i), 30(a)(ii) and Annex 1, Section 2(g).

Moreover, it has been determined, in accordance with 32 CFR parts 296 and 701, that publication of this amendment for public comment prior to adoption is impracticable, unnecessary, and contrary to public interest since it is based on technical findings that the placement of lights on this vessel in a manner differently from that prescribed herein will adversely affect the vessel's ability to perform its military functions.

List of Subjects in 32 CFR Part 706

Marine safety, Navigation (Water), and Vessels.

■ For the reasons set forth in the preamble, amend part 706 of title 32 of the Code of Federal Regulations as follows:

PART 706—CERTIFICATIONS AND EXEMPTIONS UNDER THE INTERNATIONAL REGULATIONS FOR PREVENTING COLLISIONS AT SEA, 1972

■ 1. The authority citation for 32 CFR part 706 continues to read as follows:

Authority: 33 U.S.C. 1605.

■ 2. Section 706.2 is amended in Table Two by revising the entry for USS CARL VINSON (CVN 70) to read as follows:

§ 706.2 Certifications of the Secretary of the Navy under Executive Order 11964 and 33 U.S.C. 1605.

* * * * *

Vessel	Number	Masthead lights, distance to stbd of keel in meters; Rule 21(a)	Forward anchor light, distance below flight dk in meters; § 2(K), Annex I	Forward anchor light, number of; Rule 30(a)(i)	AFT anchor light, distance below flight dk in meters; Rule 21(e), Rule 30(a)(ii)	AFT anchor light, number of; Rule 30(a)(ii)	Side lights, distance below flight dk in meters; § 2 (g), Annex I	Side lights, distance forward of forward masthead light in meters; § 3(b), Annex I	Side lights, distance inboard of ship's sides in meters; § 3(b), Annex I
* * * * * * *									
USS CARL VINSON	CVN–70	30.1	....	1	....	1	0.53	....	....
* * * * * * *									

* * * * *

Approved: May 14, 2009.

M. Robb Hyde,

Commander, JAGC, U.S. Navy Deputy Assistant Judge Advocate General (Admiralty and Maritime Law)

[FR Doc. E9–12049 Filed 5–22–09; 8:45 am]

BILLING CODE 3810–FF–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 117

[Docket No. USCG–2009–0332]

Drawbridge Operation Regulations; Shrewsbury River, Highlands, NJ

AGENCY: Coast Guard, DHS.

ACTION: Notice of temporary deviation from regulations.

SUMMARY: The Commander, First Coast Guard District, has issued a temporary deviation from the regulation governing the operation of the Route 36 Bridge, across the Shrewsbury River at mile 1.8, at Highlands, New Jersey. This deviation will allow the bridge to open on signal for all marine traffic once an hour on weekends and holidays from 12 p.m. to 8 p.m. during the boating season.

DATES: This deviation is effective from May 23, 2009, through September 7, 2009.

ADDRESSES: Documents indicated in this preamble as being available in the docket are part of docket USCG–2009–0332 and are available Online at *http://www.regulations.gov*, selecting the Advanced Docket Search option on the right side of the screen, inserting USCG–2009–0332 in the Docket ID box, pressing Enter, and then clicking on the item in the Docket ID column. This material is also available for inspection or copying at the 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, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: If you have questions on this rule, call Gary Kassof, Project Officer, First Coast Guard District; telephone (212) 668–7021. If you have questions on viewing the docket, call Renee V. Wright, Program Manager, Docket Operations, telephone 202–366–9826.

SUPPLEMENTARY INFORMATION: The Route 36 Bridge has a vertical clearance in the closed position of 35 feet at mean high water and 39 feet at mean low water. The existing drawbridge operation regulations are listed at 33 CFR 117.755(a). The bridge presently opens on the hour and half hour between 7 a.m. and 8 p.m. from May 15 through October 15, and on signal from 8 p.m. to 11 p.m. From 11 p.m. to 7 a.m. the bridge opens on signal after a four-hour advance notice is given.

The Shrewsbury River is navigated predominantly by recreational power boats and sail boats of various sizes.

Currently only one lane of vehicular traffic is open northbound on the Route 36 Bridge due to the Highlands Bridge replacement project.

As a result of the vehicular travel lane closures traffic congestion has become a major concern to motorists and local officials. The nearby Gateway National Recreation Area, operated by the National Park Service, has been particularly impacted on weekends by traffic delays as a result of the bridge construction and drawbridge openings for vessel traffic.

The National Park Service, the New Jersey Department of Transportation, and local officials have made various adjustments to traffic control to help mitigate the vehicular traffic congestion; however, the traffic congestion on weekends in the afternoon continues to be a major safety concern when motorists are exiting the Sandy Hook area and the Gateway National Recreation Park.

As a result, the National Park Service and the New Jersey Department of Transportation requested a temporary deviation from the drawbridge operation regulations to help facilitate a balance between vehicular traffic and marine traffic during the summer boating season.

Under this temporary deviation, in effect from May 23, 2009 through September 7, 2009, the Route 36 Bridge at mile 1.8, across the Shrewsbury River, shall operate as follows:

Monday through Friday, the draw shall open on signal, from 7 a.m. to 8 p.m., on the hour and half hour only. From 8 p.m. to 11 p.m. the draw shall open on signal. From 11 p.m. to 7 a.m. the draw shall open on signal after at least a four-hour notice is given by calling the number posted at the bridge.

Saturday, Sunday and holidays, the draw shall open on signal from 7 a.m. through noon, on the hour and half hour. From noon through 8 p.m., the draw shall open on signal once an hour, on the hour only. From 8 p.m. to 11 p.m. the draw shall open on signal. From 11 p.m. to 7 a.m. the draw shall open on signal after at least a four-hour advance notice is given by calling the number posted at the bridge.

In accordance with 33 CFR 117.35(e), the bridge must return to its regular operating schedule immediately at the end of the designated time period. This deviation from the operating regulations is authorized under 33 CFR 117.35.

Dated: May 13, 2009.

Gary Kassof,

Bridge Program Manager, First Coast Guard District.

[FR Doc. E9–12159 Filed 5–22–09; 8:45 am]

BILLING CODE 4910–15–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[Docket No. USCG–2009–0266]

RIN 1625–AA00

Safety Zone; Sea World May Fireworks; Mission Bay, San Diego, CA

AGENCY: Coast Guard, DHS.

ACTION: Temporary final rule.

SUMMARY: The Coast Guard is establishing a safety zone, on the navigable waters of Mission Bay in support of the Sea World May Fireworks. This safety zone is necessary to provide for the safety of the participants, crew, spectators, participating vessels, and other vessels and users of the waterway. Persons and vessels are prohibited from entering into, transiting through, or anchoring within this safety zone unless authorized by the Captain of the Port, or his designated representative.

DATES: This rule is effective from 8 p.m. on May 30, 2009 through 10 p.m. on May 31, 2009.

ADDRESSES: Documents indicated in this preamble as being available in the docket are part of docket USCG–2009–0266 and are available online by going to *http://www.regulations.gov,* selecting the Advanced Docket Search option on the right side of the screen, inserting USCG–2009–0266 in the Docket ID box, pressing Enter, and then clicking on the item in the Docket ID column. They are also available for inspection or copying at two locations: The 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, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays, and the Coast Guard Sector San Diego, 2710 N. Harbor Drive, San Diego, CA 92101–1064 between 8 a.m. and 3 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: If you have questions on this temporary rule, call Petty Officer Shane Jackson, Waterways Management, U.S. Coast Guard Sector San Diego, CA at telephone (619) 278–7262. If you have questions on viewing the docket, call Renee V. Wright, Program Manager, Docket Operations, telephone 202–366–9826.

SUPPLEMENTARY INFORMATION:

Regulatory Information

The Coast Guard is issuing this temporary final rule without prior notice and opportunity to comment pursuant to authority under section 4(a) of the Administrative Procedure Act (APA) (5 U.S.C. 553(b)). This provision authorizes an agency to issue a rule without prior notice and opportunity to comment when the agency for good cause finds that those procedures are ''impracticable, unnecessary, or contrary to the public interest.'' Under 5 U.S.C. 553(b)(B), the Coast Guard finds that good cause exists for not publishing a notice of proposed rulemaking (NPRM) with respect to this rule because immediate action is necessary to ensure the safety of vessels, spectators, participants, and others in the vicinity of the marine event on the dates and times this rule will be in effect and delay would be contrary to the public interest.

Under 5 U.S.C. 553(d)(3), the Coast Guard finds that good cause exists for making this rule effective less than 30 days after publication in the **Federal Register** because delaying the effective date would be contrary to the public interest, since immediate action is needed to ensure the public's safety.

Background and Purpose

Sea World is sponsoring the Sea World Spring Nights Fireworks, which will include a fireworks presentation from a barge in Mission Bay. The safety zone will be a 600-foot radius around the barge in approximate position 32°46′03″ N, 117°13′11″ W. This temporary safety zone is necessary to provide for the safety of the crew, spectators, participants, and other vessels and users of the waterway.

Discussion of Rule

The Coast Guard is establishing a safety zone that will be enforced from 8 p.m. to 10 p.m. on May 30, 2009 and May 31, 2009. The limits of the safety zone will be a 600-foot radius around the barge in approximate position 32°46′03″ N, 117°13′11″ W. The safety zone is necessary to provide for the safety of the crew, spectators, participants, and other vessels and users of the waterway. Persons and vessels are prohibited from entering into, transiting through, or anchoring within this safety zone unless authorized by the Captain of the Port, or his designated representative.

Regulatory Analyses

We developed this 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.

Regulatory Planning and Review

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

We expect the economic impact of this rule to be so minimal that a full Regulatory Evaluation is unnecessary. This determination is based on the size and location of the safety zone. Commercial vessels will not be hindered by the safety zone. Recreational vessels will not be allowed to transit through the designated safety zone during the specified times.

Small Entities

Under the Regulatory Flexibility Act (5 U.S.C. 601–612), we have considered whether this rule would have a significant economic impact on a substantial number of small entities. The term ''small entities'' comprises small businesses, not-for-profit organizations that are independently owned and operated and are not dominant in their fields, and governmental jurisdictions with populations of less than 50,000.

The Coast Guard certifies under 5 U.S.C. 605(b) that this rule will not have a significant economic impact on a substantial number of small entities.

This rule will not have a significant economic impact on a substantial number of small entities for the following reasons: Vessel traffic can pass safely around the safety zone. Before the effective period, the coast Guard will publish a local notice to mariners (LNM) and will issue broadcast notice to mariners (BNM) alerts via marine channel 16 VHF before the safety zone is enforced.

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 rule so that they can better evaluate its effects on them and participate in the rulemaking process.

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

Collection of Information

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

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.

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 will not result in such an expenditure, we do discuss the effects of this rule elsewhere in this preamble.

Taking of Private Property

This rule will not effect a taking of private property or otherwise have taking implications under Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

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.

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.

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.

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.

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.

Environment

We have analyzed this rule under Department of Homeland Security Management Directive 023–01 and Commandant Instruction M16475.lD, which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321–4370f), and have concluded this action 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 figure 2–1, paragraph (34)(g), of the Instruction. This rule involves the establishment of a temporary safety zone around a fireworks barge. An environmental analysis checklist and a categorical exclusion determination are available in the docket where indicated under **ADDRESSES**.

List of Subjects in 33 CFR Part 165

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

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

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

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

Authority: 33 U.S.C. 1226, 1231; 46 U.S.C. Chapter 701, 3306, 3703; 50 U.S.C. 191, 195; 33 CFR 1.05–1, 6.04–1, 6.04–6, and 160.5; Public Law 107–295, 116 Stat. 2064; Department of Homeland Security Delegation No. 0170.1.

■ 2. Add new temporary zone § 165.T11–186 to read as follows:

§ 165.T11–186 Safety zone; Sea World May Fireworks; Mission Bay, San Diego, California.

(a) *Location.* The limits of the safety zone will include a 600 foot radius around the barge in approximate position 32°46′03″ N, 117°13′11″ W.

(b) *Enforcement Period.* This section will be enforced from 8 p.m. to 10 p.m. on May 30, 2009 and May 31, 2009. If the event concludes prior to the scheduled termination time, the Captain of the Port will cease enforcement of this safety zone and will announce that fact via Broadcast Notice to Mariners.

(c) *Definitions.* The following definition applies to this section: *designated representative,* means any commissioned, warrant, and petty officers of the Coast Guard on board Coast Guard, Coast Guard Auxiliary, and local, State, and Federal law enforcement vessels who have been authorized to act on the behalf of the Captain of the Port.

(d) *Regulations.* (1) Entry into, transit through or anchoring within this safety zone is prohibited unless authorized by the Captain of the Port of San Diego or his designated on-scene representative.

(2) Mariners requesting permission to transit through the safety zone may request authorization to do so from the Sector San Diego Command Center. The Command Center may be contacted on VHF–FM Channel 16.

(3) All persons and vessels shall comply with the instructions of the Coast Guard Captain of the Port or the designated representative.

(4) Upon being hailed by U.S. Coast Guard patrol personnel by siren, radio, flashing light, or other means, the operator of a vessel shall proceed as directed.

(5) The Coast Guard may be assisted by other Federal, State, or local agencies.

Dated: May 5, 2009.

T.H. Farris,

Captain, U.S. Coast Guard, Captain of the Port San Diego.

[FR Doc. E9–12061 Filed 5–22–09; 8:45 am]

BILLING CODE 4910–15–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[Docket No. USCG–2009–0300]

RIN 1625–AA00

Safety Zone; Use of Force Training Flights, San Pablo Bay, CA

AGENCY: Coast Guard, DHS.

ACTION: Temporary final rule.

SUMMARY: The Coast Guard is establishing a temporary safety zone in the navigable waters of San Pablo Bay, California for training purposes. This safety zone is established to ensure the safety of the public and participating crews from potential hazards associated with fast-moving Coast Guard small boats taking part in the exercises. Blank ammunition will be used during these exercises. Unauthorized persons or vessels are prohibited from entering into, transiting through, or remaining in the safety zone without permission of the Captain of the Port San Francisco or his designated representative.

DATES: This safety zone is effective from May 5, 2009, to December 31, 2009. See **SUPPLEMENTARY INFORMATION** section for dates of actual training events.

ADDRESSES: Documents indicated in this preamble as being available in the docket are part of docket USCG–2009–0300 and are available online by going to *http://www.regulations.gov*, selecting the Advanced Docket Search option on the right side of the screen, inserting USCG–2009–0300 in the Docket ID box, pressing Enter, and then clicking on the item in the Docket ID column. They are also available for inspection or copying at the 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, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: If you have questions on this temporary rule, call or e-mail Lieutenant Junior Grade Simone Mausz U.S. Coast Guard Sector San Francisco; telephone (415) 399–7442, e-mail, *simone.mausz@uscg.mil.* If you have questions on viewing the docket, call Renee V. Wright, Program Manager, Docket Operations, telephone 202–366–9826.

SUPPLEMENTARY INFORMATION:

Regulatory Information

We did not publish a notice of proposed rulemaking (NPRM) for this regulation. The Coast Guard is establishing this safety zone to conduct mission-essential training directly related to military operations and national security. Accordingly, based on the military function exception to the Administrative Procedure Act, 5 U.S.C. 553(a)(1), notice and comment rulemaking under 5 U.S.C. 553(b) and an effective date of 30 days after publication under 5 U.S.C. 553(d) are not required for this rule.

Even if the Coast Guard were required to comply with the notice and comment provisions of the Administrative Procedure Act, under 5 U.S.C. 553(b)(B), we find that good cause exists for not publishing an NPRM. This exercise is necessary to train and qualify Coast Guard personnel in the use of weapons. This training is necessary to ensure that Coast Guard personnel are properly trained and qualified to conduct military and national security operations to secure ports and waterways. Failure to conduct this required training at this time will result in a lapse in personnel qualifications and, consequently, impair the ability of Coast Guard personnel to carry out important national security functions at any time. It is impracticable, unnecessary, and contrary to the public interest to delay the issuance of this rule. Further, any delay in the effective date of this rule would expose mariners to the potential hazards posed by the exercises.

For the same reasons, the Coast Guard also finds under 5 U.S.C. 553(d)(3) that good cause exists for making this rule effective less than 30 days after publication in the **Federal Register**.

Background and Purpose

U.S. Coast Guard Air Station San Francisco will be conducting airborne use of force training flights on May 5, 8, 19, 22; June 9, 11, 30; July 2, 14, 17, 28, 31; and every Tuesday, Thursday, and Friday from August 1, 2009 to December 31, 2009 in the waters of San Pablo Bay, California. The exercises are designed to train and test Coast Guard personnel in the judgment and decision-making processes necessary to safely and effectively employ use of force during homeland security incidents. The training will generally involve the use of Coast Guard helicopters to intercept fast-moving, evasive small boats on the water. The helicopter crews will fire weapons at the small boats using blank ammunition and catch bags to ensure that cartridges and other debris do not fall to the water. This safety zone is issued to establish a temporary restricted area in San Pablo Bay around the training site.

Discussion of Rule

The Coast Guard is establishing a temporary safety zone in the navigable waters of San Pablo Bay, California. During the exercises, the safety zone applies to the waters, from the surface to the seafloor, enclosed within lines connecting the following points: Beginning at 38°05′11″ N, 122°22′10″ W; thence to 38°03′44″ N, 122°20′12″ W; thence to 38°00′41″ N, 122°25′28″ W; thence to 38°01′45″ N, 122°26′38″ W; thence back to 38°05′11″ N, 122°22′10″ W (NAD 83).

The effect of the temporary safety zone will be to restrict navigation in the vicinity of the exercises. Except for persons or vessels authorized by the Coast Guard Patrol Commander, no person or vessel may enter or remain in the restricted area. These regulations are intended to keep the public a safe distance away from the participating small boats and to ensure the safety of transiting vessels.

Regulatory Analyses

We developed this 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.

Regulatory Planning and Review

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

Although this rule restricts access to the waters encompassed by the safety zone, the effect of this rule will not be significant because the local waterway users will be notified via public Broadcast Notice to Mariners to ensure the safety zone will result in minimum impact. The entities most likely to be affected are pleasure craft engaged in recreational activities.

Small Entities

Under the Regulatory Flexibility Act (5 U.S.C. 601–612), we have considered whether this rule would have a significant economic impact on a substantial number of small entities. The term ''small entities'' comprises small businesses, not-for-profit organizations that are independently owned and operated and are not dominant in their fields, and governmental jurisdictions with populations of less than 50,000.

The Coast Guard certifies under 5 U.S.C. 605(b) that this rule will not have a significant economic impact on a substantial number of small entities.

This rule may affect owners and operators of pleasure craft engaged in recreational activities and sightseeing. This rule will not have a significant economic impact on a substantial number of small entities for several reasons: (i) Vessel traffic can pass safely around the area; (ii) vessels engaged in recreational activities and sightseeing have ample space outside of the effected portion of San Pablo Bay to engage in these activities; (iii) this rule will encompass only a small portion of the waterway for a limited period of time; and, (iv) the maritime public will be advised in advance of this safety zone via Broadcast Notice to Mariners.

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 rule so that they can better evaluate its effects on them and participate in the rulemaking process.

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

Collection of Information

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

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.

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 will not result in such an expenditure, we do discuss the effects of this rule elsewhere in this preamble.

Taking of Private Property

This rule will not effect a taking of private property or otherwise have taking implications under Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

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.

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.

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.

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.

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.

Environment

We have analyzed this rule under Department of Homeland Security Management Directive 0023.1 and Commandant Instruction M16475.lD, which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321–4370f), and have concluded this action 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 figure 2–1, paragraph (34)(g), of the Instruction, from further environmental documentation because this rule establishes a safety zone.

An environmental analysis checklist and a categorical exclusion determination are available in the docket where indicated under **ADDRESSES**.

List of Subjects in 33 CFR Part 165

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

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

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

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

Authority: 33 U.S.C. 1226, 1231; 46 U.S.C. Chapter 701, 3306, 3703; 50 U.S.C. 191, 195; 33 CFR 1.05–1, 6.04–1, 6.04–6, and 160.5; Pub. L. 107–295, 116 Stat. 2064; Department of Homeland Security Delegation No. 0170.1.

■ 2. Add temporary § 165.T11–194 to read as follows:

§ 165.T11–194 Safety Zone; Coast Guard Air Station San Francisco Airborne Use of Force Judgmental Training Flights.

(a) *Location.* The following area is a safety zone: All waters of San Pablo Bay, California from surface to bottom, encompassed by lines connecting the following points: Beginning at 38°05′11″ N, 122°22′10″ W; thence to 38°03′44″ N, 122°20′12″ W; thence to 38°00′41″ N, 122°25′28″ W; thence to 38°01′45″ N, 122°26′38″ W; thence back to 38°05′11″ N, 122°22′10″ W (NAD 83).

(b) *Definitions.* As used in this section, ‘‘designated representative’’ means a Coast Guard Patrol Commander, including a Coast Guard coxswain, petty officer, or other officer operating a Coast Guard vessel or a Federal, State, or local officer assisting the Captain of the Port (COTP) San Francisco in the enforcement of the safety zone.

(c) *Regulations.* (1) Under the general regulations in § 165.23 of this title, entry into, transiting, or anchoring within this safety zone is prohibited unless authorized by the COTP or the COTP's designated representative.

(2) The safety zone is closed to all vessel traffic, except as may be permitted by the COTP or the COTP's designated representative.

(3) Vessel operators desiring to enter or operate within the safety zone must contact the COTP or the COTP's representative to obtain permission to do so. Vessel operators given permission to enter or operate in the safety zone must comply with all directions given to them by the COTP or the COTP's designated representative. Persons and vessels may request permission to enter the safety zone by contacting the Patrol Commander on VHF–16 or through the Coast Guard Command Center at telephone (415) 399–3547.

(d) *Effective period.* This section is effective from 9 a.m. to 11 p.m., each day, May 5, 8, 19, 22; June 9, 11, 30; July 2, 14, 17, 28, 31; and every Tuesday, Thursday, and Friday from August 1, 2009 to December 31, 2009.

Dated: May 1, 2009.

P.M. Gugg,

Captain, U.S. Coast Guard, Captain of the Port San Francisco.

[FR Doc. E9–12064 Filed 5–22–09; 8:45 am]

BILLING CODE 4910–15–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[Docket No. USCG–2009–0242]

RIN 1625–AA00

Safety Zone; Copper Canyon Clean Up; Lake Havasu, AZ

AGENCY: Coast Guard, DHS.

ACTION: Temporary final rule.

SUMMARY: The Coast Guard is establishing a safety zone upon the navigable waters of Lake Havasu in support of the Copper Canyon Clean up. This safety zone is necessary to provide for the safety of the participants, crew, spectators, participating vessels, and other vessels and users of the waterway. Persons and vessels are prohibited from entering into, transiting through, or anchoring within this safety zone unless authorized by the Captain of the Port, or his designated representative.

DATES: This rule is effective from 7 a.m. through 11 a.m. on May 26, 2009.

ADDRESSES: Documents indicated in this preamble as being available in the docket are part of docket USCG–2009–0242 and are available online by going to *http://www.regulations.gov,* selecting the Advanced Docket Search option on the right side of the screen, inserting USCG–2009–0242 in the Docket ID box, pressing Enter, and then clicking on the item in the Docket ID column. They are also available for inspection or copying at two locations: The 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, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays, and the Coast Guard Sector San Diego, 2710 N. Harbor Drive, San Diego, CA 92101–1064 between 8 a.m. and 3 p.m., Monday through Friday, except Federal holidays between 8 a.m. and 3 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: If you have questions on this temporary rule, call Petty Officer Shane Jackson, Waterways Management, U.S. Coast Guard Sector San Diego, CA at telephone (619) 278–7262. If you have questions on viewing the docket, call Renee V. Wright, Program Manager, Docket Operations, telephone 202–366–9826.

SUPPLEMENTARY INFORMATION:

Regulatory Information

The Coast Guard is issuing this temporary final rule without prior notice and opportunity to comment pursuant to authority under section 4(a) of the Administrative Procedure Act (APA) (5 U.S.C. 553(b)). This provision authorizes an agency to issue a rule without prior notice and opportunity to comment when the agency for good cause finds that those procedures are ‘‘impracticable, unnecessary, or contrary to the public interest.’’ Under 5 U.S.C. 553(b)(B), the Coast Guard finds that good cause exists for not publishing a notice of proposed rulemaking (NPRM) with respect to this rule because immediate action is necessary to ensure the safety of spectators, crew, participants, and other users and vessels of the waterway in the vicinity of the event on the dates and times this rule will be in effect and delay would be contrary to the public interest.

Under 5 U.S.C. 553(d)(3), the Coast Guard finds that good cause exists for making this rule effective less than 30 days after publication in the **Federal Register.** Any delay in the effective date of this rule would expose the divers to danger from transiting vessels.

Background and Purpose

The Lake Havasu Divers Association is sponsoring the Copper Canyon Clean up, which will involve 40 divers cleaning the river bottom in Lake Havasu. The safety zone will be a 500 foot radius around the divers as they move along the river bottom.

This temporary safety zone is necessary to prevent vessels from transiting the area and to protect the divers and equipment from potential damage and injury.

Discussion of Rule

The Coast Guard is establishing a safety zone that will be enforced from 7 a.m. to 11 a.m. on May 26, 2009. The limits of the safety zone will include all waters of Copper Canyon extending from the surface to the river bottom, within 500 feet of the divers. The safety zone is necessary to provide for the safety of the crew, spectators, participants, and other vessels and users of the waterway. Persons and vessels are prohibited from entering into, transiting through, or anchoring within this safety zone unless authorized by the Captain of the Port, or his designated representative.

Regulatory Analyses

We developed this 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.

Regulatory Planning and Review

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

We expect the economic impact of this rule to be so minimal that a full Regulatory Evaluation is unnecessary. This determination is based on the size and location of the safety zone. Commercial vessels will not be hindered by the safety zone. Recreational vessels will not be allowed to transit through the designated safety zone during the specified times.

Small Entities

Under the Regulatory Flexibility Act (5 U.S.C. 601–612), we have considered whether this rule would have a significant economic impact on a substantial number of small entities. The term ''small entities'' comprises small businesses, not-for-profit organizations that are independently owned and operated and are not dominant in their fields, and governmental jurisdictions with populations of less than 50,000.

The Coast Guard certifies under 5 U.S.C. 605(b) that this rule will not have a significant economic impact on a substantial number of small entities.

This rule will not have a significant economic impact on a substantial number of small entities for the following reasons: Vessel traffic can pass safely around the safety zone. Before the effective period, the coast Guard will publish a local notice to mariners (LNM) and will issue broadcast notice to mariners (BNM) alerts via marine channel 16 VHF before the safety zone is enforced.

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 rule so that they can better evaluate its effects on them and participate in the rulemaking process.

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

Collection of Information

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

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.

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 will not result in such an expenditure, we do discuss the effects of this rule elsewhere in this preamble.

Taking of Private Property

This rule will not effect a taking of private property or otherwise have taking implications under Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

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.

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.

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.

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.

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.

Environment

We have analyzed this rule under Department of Homeland Security Management Directive 0023–01 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 figure 2–1, paragraph (34)(g), of the Instruction. This rule involves the establishment of a safety zone to provide for the safety of the participants, crew, spectators, participating vessels, and other vessels and users of the waterway. An environmental analysis checklist and a categorical exclusion determination are available in the docket where indicated under ADDRESSES.

List of Subjects in 33 CFR Part 165

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

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

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

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

Authority: 33 U.S.C. 1226, 1231; 46 U.S.C. Chapter 701, 3306, 3703; 50 U.S.C. 191, 195; 33 CFR 1.05–1, 6.04–1, 6.04–6, and 160.5; Pub. L. 107–295, 116 Stat. 2064; Department of Homeland Security Delegation No. 0170.1.

■ 2. Add new temporary zone § 165.T11–179 to read as follows:

§ 165.T11–179 Safety zone; Copper Canyon Clean up; Lake Havasu, Arizona

(a) *Location.* The limits of the safety zone will include all waters of Copper Canyon extending from the surface to the river bottom, within 500 feet of the divers.

(b) *Enforcement Period.* This section will be enforced from 7 a.m. to 11 a.m. on May 26, 2009. If the event concludes prior to the scheduled termination time, the Captain of the Port will cease enforcement of this safety zone.

(c) *Definitions.* The following definition applies to this section: *Designated representative,* means any commissioned, warrant, and petty officers of the Coast Guard on board Coast Guard, Coast Guard Auxiliary, and local, state, and federal law enforcement vessels who have been authorized to act on the behalf of the Captain of the Port.

(d) *Regulations.* (1) Entry into, transit through or anchoring within this safety zone is prohibited unless authorized by the Captain of the Port of San Diego or his designated on-scene representative.

(2) All persons and vessels shall comply with the instructions of the Coast Guard Captain of the Port or the designated representative.

(3) Upon being hailed by U.S. Coast Guard patrol personnel by siren, radio, flashing light, or other means, the operator of a vessel shall proceed as directed.

(4) The Coast Guard may be assisted by other federal, state, or local agencies.

Dated: May 4, 2009.

T.H. Farris,

Captain, U.S. Coast Guard, Captain of the Port San Diego.

[FR Doc. E9–12062 Filed 5–22–09; 8:45 am]

BILLING CODE 4910–15–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R03–OAR–2009–0058; FRL–8909–5]

Approval and Promulgation of Air Quality Implementation Plans; Maryland; Reasonably Available Control Technology Requirements for Volatile Organic Compounds: Correction

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; correcting amendment.

SUMMARY: This document corrects errors in the amendatory instructions regarding EPA's action to convert Maryland regulations governing volatile organic compound (VOC) reasonable available control technology (RACT) from conditional limited approval to full approval.

DATE: *Effective Date:* May 26, 2009.

FOR FURTHER INFORMATION CONTACT: Jacqueline Lewis, (215) 814–2037, or by e-mail at *lewis.jacqueline@epa.gov.*

SUPPLEMENTARY INFORMATION: Throughout this document wherever ‘‘we’’ or ‘‘our’’ are used we mean EPA. On March 25, 2009 (74 FR 12556), we published a final rulemaking action announcing our approval of State Implementation Plan (SIP) revisions to Maryland regulations (COMAR 26.11.19.02G and COMAR 26.11.06.06) governing VOC RACT. In that document, we provided an incorrect amendatory instruction on page 12559 regarding the removal of nonexistent tables in paragraphs 52.1072(d) and 52.1073(e). This action corrects the erroneous amendatory instruction in part 52 for these paragraphs.

In the Rule document E9–6654 published in the **Federal Register** on March 25, 2009 (74 FR 12556), Amendatory Instruction Numbers 3 and 4 on page 12559, second and third columns respectively are revised to read as follows:

‘‘3. In § 52.1072, paragraph (d) is removed and reserved.

4. In § 52.1073, paragraph (e) is removed and reserved.’’

Section 553 of the Administrative Procedure Act, 5 U.S.C. 553(b)(B), provides that, when an agency for good cause finds that notice and public procedure are impracticable, unnecessary or contrary to the public interest, the agency may issue a rule without providing notice and an opportunity for public comment. We have determined that there is good cause for making today's rule final without prior proposal and opportunity for comment because this rule is not substantive and imposes no regulatory requirements, but merely corrects a citation in a previous action. Thus, notice and public procedure are unnecessary. We find that this constitutes good cause under 5 U.S.C. 553(b)(B).

Statutory and Executive Order Reviews

Under Executive Order (E.O.) 12866 (58 FR 51735, October 4, 1993), this action is not a ‘‘significant regulatory action’’ and is therefore not subject to review by the Office of Management and Budget. For this reason, this action is also not subject to Executive Order 13211, ‘‘Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use’’ (66 FR 28355 (May 22, 2001)). Because the agency has made a ‘‘good cause’’ finding that this action is not subject to notice-and-comment requirements under the Administrative

Procedures Act or any other statute as indicated in the **SUPPLEMENTARY INFORMATION** section above, it is not subject to the regulatory flexibility provisions of the Regulatory Flexibility Act (5 U.S.C 601 et *seq.*), or to sections 202 and 205 of the Unfunded Mandates Reform Act of 1995 (UMRA) (Pub. L. 104–4). In addition, this action does not significantly or uniquely affect small governments or impose a significant intergovernmental mandate, as described in sections 203 and 204 of UMRA. This rule also 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, as specified by Executive Order 13175 (65 FR 67249, November 9, 2000), nor will it 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 governments, as specified by Executive Order 13132 (64 FR 43255, August 10, 1999). This rule also is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997), because it approves a State rule implementing a Federal standard.

This technical correction action does not involve technical standards; thus the requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) do not apply. The rule also does not involve special consideration of environmental justice related issues as required by Executive Order 12898 (59 FR 7629, February 16, 1994). In issuing this rule, EPA has taken the necessary steps to eliminate drafting errors and ambiguity, minimize potential litigation, and provide a clear legal standard for affected conduct, as required by section 3 of Executive Order 12988 (61 FR 4729, February 7, 1996). EPA has complied with Executive Order 12630 (53 FR 8859, March 15, 1998) by examining the takings implications of the rule in accordance with the ''Attorney General's Supplemental Guidelines for the Evaluation of Risk and Avoidance of Unanticipated Takings'' issued under the executive order. This rule does not impose an information collection burden under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq*).

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. Section 808 allows the issuing agency to make a rule effective sooner than otherwise provided by the CRA if the agency makes a good cause finding that notice and public procedure is impracticable, unnecessary or contrary to the public interest. This determination must be supported by a brief statement. 5 U.S.C. 808(2). As stated previously, EPA had made such a good cause finding, including the reasons therefore, and established an effective date of May 26, 2009. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. This correction for 40 CFR part 52, subpart V (Maryland) is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Ozone, Volatile organic compounds.

Dated: May 14, 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 revising the entry for COMAR 26.11.19.02G 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
* *	*	*	* *	*
	26.11.19 Volatile Organic Compounds from Specific Processes			
26.11.19.02	Applicability, Determining Compliance, Reporting, and General Requirements.	5/4/98, 12/10/01	3/25/09, 74 FR 12556	(c) (174), (c) (175). On 2/27/03 (68 FR 9012), EPA approved a revised rule citation with a State effective date of 5/8/95 [(c)(182)(i)(D)].
* *	*	*	* *	

* * * * *

■ 3. In § 52.1072, paragraph (d) is removed and reserved.

■ 4. In § 52.1073, paragraph (e) is removed and reserved.

[FR Doc. E9–12139 Filed 5–22–09; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2008–0270; FRL–8413–7]

Acibenzolar-S-methyl; Pesticide Tolerances

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation establishes tolerances for residues of acibenzolar-S-methyl in or on onion, bulb, subgroup 3-07A; and vegetable, cucurbit, group 9. It also removes the section 18 time-limited tolerance on onion, bulb which is superseded by the new tolerance on onion, bulb, subgroup 3-07A. Interregional Research Project Number 4 (IR-4) and Syngenta Crop Protection requested these tolerances under the Federal Food, Drug, and Cosmetic Act (FFDCA).

DATES: This regulation is effective May 26, 2009. Objections and requests for hearings must be received on or before July 27, 2009, and must be filed in accordance with the instructions provided in 40 CFR part 178 (see also Unit I.C. of the **SUPPLEMENTARY INFORMATION**).

ADDRESSES: EPA has established a docket for this action under docket identification (ID) number EPA–HQ–OPP–2008–0270. All documents in the docket are listed in the docket index available at *http://www.regulations.gov*. 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 in the electronic docket at *http://www.regulations.gov*, or, if only available in hard copy, at the OPP Regulatory Public Docket in Rm. S–4400, One Potomac Yard (South Bldg.), 2777 S. Crystal Dr., Arlington, VA. The Docket Facility is open from 8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. The Docket Facility telephone number is (703) 305–5805.

FOR FURTHER INFORMATION CONTACT: Susan Stanton, Registration Division (7505P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001; telephone number: (703) 305–5218; e-mail address: *stanton.susan@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this Action Apply to Me?

You may be potentially affected by this action if you are an agricultural producer, food manufacturer, or pesticide manufacturer. Potentially affected entities may include, but are not limited to those engaged in the following activities:

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

This listing is not intended to be exhaustive, but rather to provide a guide for readers regarding entities likely to be affected by this action. Other types of entities not listed in this unit could also be affected. The North American Industrial Classification System (NAICS) codes have been provided to assist you and others in determining whether this action might apply to certain entities. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed under **FOR FURTHER INFORMATION CONTACT**.

B. How Can I Access Electronic Copies of this Document?

In addition to accessing electronically available documents at *http://www.regulations.gov*, you may access this **Federal Register** document electronically through the EPA Internet under the ''**Federal Register**'' listings at *http://www.epa.gov/fedrgstr*. You may also access a frequently updated electronic version of EPA's tolerance regulations at 40 CFR part 180 through the Government Printing Office's e-CFR cite at *http://www.gpoaccess.gov/ecfr*.

C. Can I File an Objection or Hearing Request?

Under section 408(g) of FFDCA, 21 U.S.C. 346a, any person may file an objection to any aspect of this regulation and may also request a hearing on those objections. You must file your objection or request a hearing on this regulation in accordance with the instructions provided in 40 CFR part 178. To ensure proper receipt by EPA, you must identify docket ID number EPA–HQ–OPP–2008–0270 in the subject line on the first page of your submission. All requests must be in writing, and must be mailed or delivered to the Hearing Clerk as required by 40 CFR part 178 on or before July 27, 2009.

In addition to filing an objection or hearing request with the Hearing Clerk as described in 40 CFR part 178, please submit a copy of the filing that does not contain any CBI for inclusion in the public docket that is described in **ADDRESSES**. Information not marked confidential pursuant to 40 CFR part 2 may be disclosed publicly by EPA without prior notice. Submit this copy, identified by docket ID number EPA–HQ–OPP–2008–0270, by one of the following methods:

- *Federal eRulemaking Portal*: *http://www.regulations.gov*. Follow the on-line instructions for submitting comments.
- *Mail*: Office of Pesticide Programs (OPP) Regulatory Public Docket (7502P), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001.
- *Delivery*: OPP Regulatory Public Docket (7502P), Environmental Protection Agency, Rm. S–4400, One Potomac Yard (South Bldg.), 2777 S. Crystal Dr., Arlington, VA. Deliveries are only accepted during the Docket Facility's normal hours of operation (8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays). Special arrangements should be made for deliveries of boxed information. The Docket Facility telephone number is (703) 305–5805.

II. Petition for Tolerance

In the **Federal Register** of May 16, 2008 (73FR 28461) (FRL–8361–6), EPA issued a notice pursuant to section 408(d)(3) of FFDCA, 21 U.S.C. 346a(d)(3), announcing the filing of a pesticide petition (PP 8E7337) by Interregional Research Project Number 4 (IR-4), 500 College Road East, Suite 201W, Princeton, NJ 08540. The petition requested that 40 CFR 180.561 be amended by establishing a tolerance for residues of the fungicide acibenzolar-S-methyl, benzo(1,2,3)thiadiazole-7-carbothioic acid-S-methyl ester, in or on onion, bulb, subgroup 3-07A at 0.07 parts per million (ppm). That notice referenced a summary of the petition prepared on behalf of IR-4 by Syngenta Crop Protection, the registrant, which is available to the public in the docket, *http://www.regulations.gov*. There were no comments received in response to the notice of filing.

In the **Federal Register** of December 3, 2008 (73 FR 73644) (FRL–8386–9), EPA issued a notice pursuant to section 408(d)(3) of FFDCA, 21 U.S.C. 346a(d)(3), announcing the filing of a pesticide petition (PP 8F7352) by Syngenta Crop Protection, Regulatory Affairs, P.O. Box 18300, Greensboro, NC 27419-8300. The petition requested that 40 CFR 180.561 be amended by establishing a tolerance for residues of the fungicide acibenzolar-S-methyl, benzo(1,2,3)thiadiazole-7-carbothioic acid-S-methyl ester, in or on vegetable, cucurbit, group 9 at 1.0 ppm. That notice referenced a summary of the petition prepared by Syngenta Crop Protection, the registrant, which is available to the public in docket ID number EPA–HQ–OPP–2008–0733 at *http://www.regulations.gov*. There were no comments received in response to the notice of filing.

Based upon review of the data supporting the petitions, EPA has revised the tolerance expression and increased the tolerance level for onion, bulb, subgroup 3-07A from 0.07 ppm to 0.1 ppm; and for vegetable, cucurbit, group 9 from 1.0 ppm to 2.0 ppm. The reasons for these changes are explained in Unit IV.C.

III. Aggregate Risk Assessment and Determination of Safety

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

Consistent with section 408(b)(2)(D) of FFDCA, and the factors specified in section 408(b)(2)(D) of FFDCA, EPA has reviewed the available scientific data and other relevant information in support of this action. EPA has sufficient data to assess the hazards of and to make a determination on aggregate exposure for the petitioned-for tolerances for residues of acibenzolar-S-methyl on onion, bulb, subgroup 3-07A at 0.1 ppm; and vegetable, cucurbit, group 9 at 2.0 ppm. EPA's assessment of exposures and risks associated with establishing tolerances follows.

A. Toxicological Profile

EPA has evaluated the available toxicity data and considered its validity, completeness, and reliability as well as the relationship of the results of the studies to human risk. EPA has also considered available information concerning the variability of the sensitivities of major identifiable subgroups of consumers, including infants and children.

Acibenzolar-S-methyl showed no significant toxicity in a battery of acute toxicity tests but showed considerable skin-sensitivity. In subchronic and chronic oral studies in rats, dogs and mice, signs of mild regenerative hemolytic anemia were consistently observed in all three species. Additional toxic effects observed in these studies included decreases in body weight, body weight gain and/or food consumption. No other significant treatment-related effects of toxicological concern were observed in these subchronic and chronic oral studies. No neurotoxic effects were seen at the highest dose tested in a subchronic neurotoxicity study in rats. In a 28–day dermal toxicity study in rats no systemic or dermal effects were seen at the limit dose.

In developmental toxicity and developmental neurotoxicity (DNT) studies in rats, treatment-related effects (visceral malformations and skeletal variations; changes in brain morphometrics in the cerebellum) were observed in fetuses at levels that were not toxic to the parent, indicating increased sensitivity of rat fetuses compared to adults. Increased sensitivity was not observed in a developmental toxicity study in rabbits, or in 1-generation and 2-generation reproduction studies in rats. In a 28–day dermal developmental toxicity study in rats, no maternal or developmental toxicity was observed at dose levels up to 500 mg/kg/day, the highest dose level tested.

Acibenzolar-S-methyl was classified by EPA as a ''not likely'' human carcinogen based on the lack of evidence of carcinogenicity in male and female rats and mice and lack of evidence of genotoxicity in an acceptable battery of mutagenicity studies.

Specific information on the studies received and the nature of the adverse effects caused by acibenzolar-S-methyl as well as the no-observed-adverse-effect-level (NOAEL) and the lowest-observed-adverse-effect-level (LOAEL) from the toxicity studies can be found at *http://www.regulations.gov* in the document *Revised Acibenzolar-S-methyl Human Health Risk Assessment for Proposed Use of Acibenzolar-S-methyl on Cucurbits and Bulb Onions* page 34 in docket ID number EPA–HQ–OPP–2008–0270.

B. Toxicological Endpoints

For hazards that have a threshold below which there is no appreciable risk, a toxicological point of departure (POD) is identified as the basis for derivation of reference values for risk assessment. The POD may be defined as the highest dose at which no adverse effects are observed (the NOAEL) in the toxicology study identified as appropriate for use in risk assessment. However, if a NOAEL cannot be determined, the lowest dose at which adverse effects of concern are identified (the LOAEL) or a Benchmark Dose (BMD) approach is sometimes used for risk assessment. Uncertainty/safety factors (UFs) are used in conjunction with the POD to take into account uncertainties inherent in the extrapolation from laboratory animal data to humans and in the variations in sensitivity among members of the human population as well as other unknowns. Safety is assessed for acute and chronic dietary risks by comparing aggregate food and water exposure to the pesticide to the acute population adjusted dose (aPAD) and chronic population adjusted dose (cPAD). The aPAD and cPAD are calculated by dividing the POD by all applicable UFs. Aggregate short-term, intermediate-term, and chronic-term risks are evaluated by comparing food, water, and residential exposure to the POD to ensure that the margin of exposure (MOE) called for by the product of all applicable UFs is not exceeded. This latter value is referred to as the Level of Concern (LOC).

For non-threshold risks, the Agency assumes that any amount of exposure will lead to some degree of risk. Thus, the Agency estimates risk in terms of the probability of an occurrence of the adverse effect greater than that expected in a lifetime. For more information on the general principles EPA uses in risk characterization and a complete description of the risk assessment process, see *http://www.epa.gov/pesticides/factsheets/riskassess.htm*.

A summary of the toxicological endpoints for acibenzolar-S-methyl used for human risk assessment can be found at *http://www.regulations.gov* in the document *Revised Acibenzolar-S-*

methyl Human Health Risk Assessment for Proposed Use of Acibenzolar-S-methyl on Cucurbits and Bulb Onions page 21 in docket ID number EPA–HQ–OPP–2008–0270.

C. Exposure Assessment

1. *Dietary exposure from food and feed uses*. In evaluating dietary exposure to acibenzolar-S-methyl, EPA considered exposure under the petitioned-for tolerances as well as all existing acibenzolar-S-methyl tolerances in 40 CFR 180.561. EPA assessed dietary exposures from acibenzolar-S-methyl in food as follows:

i. *Acute exposure*. Quantitative acute dietary exposure and risk assessments are performed for a food-use pesticide, if a toxicological study has indicated the possibility of an effect of concern occurring as a result of a 1–day or single exposure. EPA identified such an effect (changes in brain morphometrics in the cerebellum of offspring) in the developmental neurotoxicity study in rats. This acute endpoint is relevant to the population subgroup, females 13 to 49 years old. No acute endpoint of concern was identified for the general population or other population subgroups.

In estimating acute dietary exposure of females 13 to 49 years old, EPA used food consumption information from the United States Department of Agriculture (USDA) 1994–1996 Nationwide Continuing Surveys of Food Intakes by Individuals (CSFII). EPA conducted a partially refined, probabilistic acute dietary exposure assessment using the distribution of residues from field trial data for each food commodity. The probabilistic assessment incorporated empirical processing factors for some processed commodities (tomato paste, puree and juice) and DEEM™ default processing factors for the remaining processed commodities. Exposure estimates were further refined using maximum percent crop treated (PCT) information for most existing uses of acibenzolar-S-methyl. EPA assumed 100 PCT for the new uses on onions and cucurbits.

The acibenzolar residues of concern for risk assessment include acibenzolar-S-methyl, benzo(1,2,3) thiadiazole-7-carbothioic acid-S-methyl ester, convertible to benzo(1,2,3)thiadiazole-7-carboxylic acid (CGA-210007), expressed as acibenzolar-S-methyl; and its 4-hydroxy CGA-210007 (CGA-323060) and 5-hydroxy CGA-210007 (CGA-324041) metabolites. A factor of 1.5x, based on the relative abundance of the hydroxy metabolites (CGA-323060 and CGA-324041) and residues convertible to the carboxylic acid metabolite (CGA-210007) found in the lettuce metabolism study, was applied to estimates of acibenzolar-S-methyl residues to account for all of the residues of concern for dietary risk (including CGA-210007, CGA-323060 and CGA-324041).

ii. *Chronic exposure*. EPA identified different chronic effects of concern for the general population (hemolytic anemia with compensatory response observed in the chronic dog study) and for females 13 to 49 years old (changes in brain morphometrics in the cerebellum of offspring in the DNT study). The cPAD for the general population has been established at 0.25 mg/kg/day; whereas, the cPAD for females 13 to 49 years old is lower (0.082 mg/kg/day), due to the more sensitive endpoint on which it is based. In conducting the chronic dietary exposure assessment EPA used the food consumption data from the USDA 1994–1996 and 1998 CSFII. As to residue levels in food, EPA assumed tolerance-level residues (adjusted by a factor of 1.5x to account for all metabolites of concern), DEEM™ default processing factors and 100 PCT for all commodities.

iii. *Cancer*. Based on the lack of evidence of carcinogenicity in male and female rats and mice and lack of evidence of genotoxicity in an acceptable battery of mutagenicity studies, EPA classified acibenzolar-S-methyl as a ''not likely'' human carcinogen. Therefore, an exposure assessment for evaluating cancer risk is not needed for this chemical.

iv. *Anticipated residue and PCT information*. Section 408(b)(2)(E) of FFDCA authorizes EPA to use available data and information on the anticipated residue levels of pesticide residues in food and the actual levels of pesticide residues that have been measured in food. If EPA relies on such information, EPA must require pursuant to FFDCA section 408(f)(1) that data be provided 5 years after the tolerance is established, modified, or left in effect, demonstrating that the levels in food are not above the levels anticipated. For the present action, EPA will issue such data call-ins as are required by FFDCA section 408(b)(2)(E) and authorized under FFDCA section 408(f)(1). Data will be required to be submitted no later than 5 years from the date of issuance of these tolerances.

Section 408(b)(2)(F) of FFDCA states that the Agency may use data on the actual percent of food treated for assessing chronic dietary risk only if:

- Condition a: The data used are reliable and provide a valid basis to show what percentage of the food derived from such crop is likely to contain the pesticide residue.
- Condition b: The exposure estimate does not underestimate exposure for any significant subpopulation group.
- Condition c: Data are available on pesticide use and food consumption in a particular area, the exposure estimate does not understate exposure for the population in such area.

In addition, the Agency must provide for periodic evaluation of any estimates used. To provide for the periodic evaluation of the estimate of PCT as required by FFDCA section 408(b)(2)(F), EPA may require registrants to submit data on PCT.

The Agency used PCT information as follows:

Broccoli 5%, cabbage 2.5%, cauliflower 5%, celery 1%, lettuce (head and leaf) 12%, pepper (bell and non-bell) 5%, spinach 30%, and tomato 5%.

In most cases, EPA uses available data from United States Department of Agriculture/National Agricultural Statistics Service (USDA/NASS), proprietary market surveys, and the National Pesticide Use Database for the chemical/crop combination for the most recent 6 years. EPA uses an average PCT for chronic dietary risk analysis. The average PCT figure for each existing use is derived by combining available public and private market survey data for that use, averaging across all observations, and rounding to the nearest 5%, except for those situations in which the average PCT is less than one. In those cases, 1% is used as the average PCT and 2.5% is used as the maximum PCT. EPA uses a maximum PCT for acute dietary risk analysis. The maximum PCT figure is the highest observed maximum value reported within the recent 6 years of available public and private market survey data for the existing use and rounded up to the nearest multiple of 5%.

The Agency believes that the three conditions discussed in Unit III.C.1.iv. have been met. With respect to Condition a, PCT estimates are derived from Federal and private market survey data, which are reliable and have a valid basis. The Agency is reasonably certain that the percentage of the food treated is not likely to be an underestimation. As to Conditions b and c, regional consumption information and consumption information for significant subpopulations is taken into account through EPA's computer-based model for evaluating the exposure of significant subpopulations including several regional groups. Use of this consumption information in EPA's risk assessment process ensures that EPA's exposure estimate does not understate exposure for any significant subpopulation group and allows the Agency to be reasonably certain that no regional population is exposed to residue levels higher than those estimated by the Agency. Other than the data available through national food consumption surveys, EPA does not have available reliable information on the regional consumption of food to which acibenzolar-S-methyl may be applied in a particular area.

2. *Dietary exposure from drinking water*. The residues of concern for drinking water include acibenzolar-S-methyl and residues convertible to CGA-210007. The Agency used screening level water exposure models in the dietary exposure analysis and risk assessment for acibenzolar-S-methyl and CGA-210007 in drinking water. These simulation models take into account data on the physical, chemical, and fate/transport characteristics of acibenzolar-S-methyl. Further information regarding EPA drinking water models used in pesticide exposure assessment can be found at *http://www.epa.gov/oppefed1/models/water/index.htm*.

Based on the Pesticide Root Zone Model/Exposure Analysis Modeling System (PRZM/EXAMS) and Screening Concentration in Ground Water (SCI-GROW) models, the estimated drinking water concentrations (EDWCs) of acibenzolar-S-methyl and CGA-210007 for acute exposures are estimated to be 0.74 and 14.21 parts per billion (ppb), respectively, for surface water and 0.000041 and 0.557 ppb, respectively, for ground water. EDWCs of acibenzolar-S-methyl and CGA-210007 for chronic exposures for non-cancer assessments are estimated to be 0.10 and 9.48 ppb, respectively, for surface water and 0.000041 and 0.557 ppb, respectively, for ground water.

Modeled estimates of drinking water concentrations were directly entered into the dietary exposure model. CGA-210007 drinking water residues were included in the dietary exposure assessment as acibenzolar-S-methyl equivalents. CGA 210007 residues were converted to acibenzolar-S-methyl equivalents based on molecular weight (mol. wt. of acibenzolar (210) ÷ mol. wt. of CGA 210007 (180) x EDWC for CGA 210007). For acute dietary risk assessment, the water concentration value of 17 ppb was used to assess the contribution to drinking water. For chronic dietary risk assessment, the water concentration of value 11 ppb was used to assess the contribution to drinking water.

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

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

EPA has not found acibenzolar-S-methyl to share a common mechanism of toxicity with any other substances, and acibenzolar-S-methyl does not appear to produce a toxic metabolite produced by other substances. For the purposes of this tolerance action, therefore, EPA has assumed that acibenzolar-S-methyl does not have a common mechanism of toxicity with other substances. For information regarding EPA's efforts to determine which chemicals have a common mechanism of toxicity and to evaluate the cumulative effects of such chemicals, see EPA's website at *http://www.epa.gov/pesticides/cumulative*.

D. Safety Factor for Infants and Children

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

In previous risk assessments for acibenzolar-S-methyl the 10X FQPA safety factor was retained for increased quantitative susceptibility (umbilical hernia) observed in a rat developmental toxicity study and the lack of a developmental-neurotoxicity (DNT) study. A DNT study has now been submitted and reviewed by EPA; and, based on reevaluation of existing data and review of newly submitted data, the umbilical hernias are no longer considered to be treatment-related. EPA concluded that the incidence of umbilical hernias at 10 milligram/kilogram/day (mg/kg/day) was not a treatment-related adverse effect because the effect is not dose-related (i.e., it was seen only at the low dose of 10 mg/kg/day); the effect was not seen in dosed animals in other studies, including developmental toxicity studies and reproduction studies; umbilical hernia was observed in the control animals in the rat dermal developmental toxicity study (1/336 fetuses in 1 of 24 litters); and the effect is known to occur spontaneously in the rat strain used in this study. New studies, including a DNT study in rats, a developmental toxicity study in rats and two non-standard investigative, phase-specific studies, support the finding that incidence of umbilical hernias is not treatment-related. Based on these findings, EPA has reconsidered the FQPA safety factor for acibenzolar-S-methyl.

2. *Prenatal and postnatal sensitivity*. The prenatal and postnatal toxicity database for acibenzolar-S-methyl includes acceptable developmental toxicity studies in rats (two oral and one dermal) and rabbits (one oral); a DNT study in the rat; and 1-generation and 2-generation reproduction toxicity studies in the rat.

There was no evidence of increased susceptibility of fetuses or offspring in the rat dermal developmental toxicity study, the rabbit developmental toxicity study or the rat reproduction toxicity studies. No maternal or fetal effects were observed in the dermal developmental study at any dose tested. In the rabbit developmental study, maternal effects (mortality, clinical signs, decreased maternal body weight and food consumption) were seen at a lower dose than fetal effects (marginal increase in vertebral anomalies). In the rat reproduction studies, parental effects (increased weights and hemosiderosis of the spleen; decreased body weight gain and food consumption in females) and offspring effects (reduced pup body weight gains and lower pup body weights during lactation) were seen at the same dose.

In the developmental toxicity and DNT studies in rats, treatment-related effects (visceral malformations and skeletal variations; and changes in brain morphometrics in the cerebellum) were observed in offspring at levels that were not toxic to the parent, indicating potential increased quantitative susceptibility of offspring compared to adults. The developmental no-observed adversed-effect level (NOAEL) from the DNT study (8.2 mg/kg/day) is the lowest NOAEL from any study in the acibenzolar database and is the POD used in both the acute and chronic dietary exposure assessments for females, 13 to 49 years old, the relevant population subgroup for assessing potential developmental effects. Since there is a well-defined NOAEL for these effects and the NOAEL is being used as the POD in the risk assessment, there are no residual uncertainties with regard to pre- or postnatal sensitivity.

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

i. The toxicity database for acibenzolar-S-methyl is complete, except for immunotoxicity studies, and EPA has determined that an additional uncertainty factor is not required to account for potential immunotoxicity. The reasons for this determination are explained below:

EPA began requiring functional immunotoxicity testing of all food and non-food use pesticides on December 26, 2007. Since this requirement is relatively new, these studies are not yet available for acibenzolar-S-methyl. In the absence of specific immunotoxicity studies, EPA has evaluated the available acibenzolar-S-methyl toxicity data to determine whether an additional database uncertainty factor is needed to account for potential immunotoxicity. There are no indications in the available studies that organs associated with immune function, such as the thymus and spleen, are affected by acibenzolar-S-methyl. While effects on the spleen were observed in association with hematologic effects, these were considered to be secondary to the primary effects on blood hematology. Effects on the thymus were seen in only one study in one animal at a high dose (400 mg/kg/day) and were, therefore, considered to be spurious. Due to the lack of evidence of immunotoxicity for acibenzolar-S-methyl, EPA does not believe that conducting immunotoxicity testing will result in a NOAEL less than the chronic NOAELs of 8.2 mg/kg/day (females, 13 to 49 years old) or 25 mg/kg/day (all other populations) already established for acibenzolar-S-methyl, and an additional factor (UFDB) for database uncertainties is not needed to account for potential immunotoxicity.

ii. There was no evidence of neurotoxicity in the subchronic neurotoxicity study submitted for acibenzolar-S-methyl. Based on the results of this study, EPA has determined that an acute neurotoxicity study is not required. There was evidence of offspring neurotoxicity (changes in brain morphometrics in the cerebellum) in the rat DNT study in the absence of maternal toxicity; however, since the NOAEL for these effects is being used in the acute and chronic risk assessments for females, 13 to 49 years old, there are no residual uncertainties with regard to these effects and no need for additional UFs to account for neurotoxicity.

iii. Although there was evidence of increased quantitative susceptibility of offspring to acibenzolar-S-methyl in the rat developmental toxicity and DNT studies, the Agency did not identify any residual uncertainties after establishing toxicity endpoints and traditional UFs to be used in the risk assessment.

iv. There are no residual uncertainties identified in the exposure databases. The dietary food exposure assessments were performed using tolerance levels or anticipated residues derived from reliable field trials and screening-level PCT estimates. EPA made conservative (protective) assumptions in the ground water and surface water modeling used to assess exposure to acibenzolar-S-methyl in drinking water. Residential exposure to acibenzolar-S-methyl is not expected. These assessments will not underestimate the exposure and risks posed by acibenzolar-S-methyl.

E. Aggregate Risks and Determination of Safety

EPA determines whether acute and chronic pesticide exposures are safe by comparing aggregate exposure estimates to the acute population adjusted dose (aPAD) and chronic population adjusted dose (cPAD). The aPAD and cPAD represent the highest safe exposures, taking into account all appropriate SFs. EPA calculates the aPAD and cPAD by dividing the POD by all applicable UFs. For linear cancer risks, EPA calculates the probability of additional cancer cases given the estimated aggregate exposure. Short-term, intermediate-term, and chronic-term risks are evaluated by comparing the estimated aggregate food, water, and residential exposure to the POD to ensure that the MOE called for by the product of all applicable UFs is not exceeded.

1. *Acute risk*. An acute aggregate risk assessment takes into account exposure estimates from acute dietary consumption of food and drinking water. Using the exposure assumptions discussed in this unit for acute exposure, the acute dietary exposure from food and water to acibenzolar-S-methyl will occupy 12% of the aPAD for females, 13 to 49 years old, the only population group for which an acute endpoint of toxicological concern was identified.

2. *Chronic risk*. EPA performed two different chronic risk assessments – one focusing on females 13 to 49 years old and designed to protect against neurotoxic effects in offspring and the other focusing on chronic effects (hemolytic anemia) relevant to all other population groups. The more sensitive chronic endpoint was seen as to offspring effects rather than other chronic effects. Using the exposure assumptions described in this unit for chronic exposure, EPA has concluded that for females, 13 to 49 years old, chronic exposure to acibenzolar-S-methyl from food and water will utilize 5% of the cPAD addressing offspring effects. As to other chronic effects, chronic exposure to acibenzolar-S-methyl from food and water will utilize 4% of the cPAD for children, 1 to 2 years old, the population group receiving the greatest exposure. There are no residential uses for acibenzolar-S-methyl.

3. *Short-term intermediate-term risk*. Short-term and intermediate-term aggregate exposures take into account short-term and intermediate-term residential exposure plus chronic exposure to food and water (considered to be a background exposure level). Acibenzolar-S-methyl is not registered for any use patterns that would result in residential exposure. Therefore, the short-term and intermediate-term aggregate risk is the sum of the risk from exposure to acibenzolar-S-methyl through food and water and will not be greater than the chronic aggregate risk.

4. *Aggregate cancer risk for U.S. population*. Acibenzolar is classified as a ''not likely'' human carcinogen and is, therefore, not expected to pose a cancer risk.

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

IV. Other Considerations

A. Analytical Enforcement Methodology

Adequate enforcement methodology (High Performance Liquid Chromatography with Ultraviolet Detection (HPLC/UV) Method AG-671A) is available to enforce the tolerance expression. The method may be requested from: Chief, Analytical Chemistry Branch, Environmental Science Center, 701 Mapes Rd., Ft. Meade, MD 20755–5350; telephone number: (410) 305–2905; e-mail address: *residuemethods@epa.gov*.

B. International Residue Limits

No Codex, Mexican or Canadian maximum residue limits have been established for acibenzolar-S-methyl on any commodity.

C. Revisions to Petitioned-For Tolerances

The petitioners proposed tolerances for residues of ''acibenzolar-S-methyl, benzo(1,2,3)thiadiazole-7-carbothioic acid-S-methyl ester.'' Since the analytical method for acibenzolar is a common-moiety method that converts all residues containing the benzo(1,2,3)thiadiazole-7-carboxylic acid (CGA-210007) moiety to CGA-210007, EPA has revised the tolerance expression to read ''acibenzolar-S-methyl, benzo(1,2,3)thiadiazole-7-carbothioic acid-S-methyl ester, including its metabolites and degradates.

EPA has also increased the tolerance level for onion, bulb, subgroup 3-07A from 0.07 ppm to 0.1 ppm; and for vegetable, cucurbit, group 9 from 1.0 ppm to 2.0 ppm. The residue data submitted for onions and previously submitted data for tobacco suggest that drying may tend to concentrate residues of acibenzolar-S-methyl. To ensure that the tolerance level is adequate, EPA has increased the tolerance for onion, bulb, subgroup 3-07A from 0.07 to 0.1 ppm. EPA increased the tolerance for cucurbits from 1.0 to 2.0 ppm based on the indication of variability within and between the cucurbit vegetable data sets (cantaloupe, cucumber and summer squash), as well as the demonstrated potential for significant increases in acibenzolar-S-methyl residues 0 to 7 days before harvest.

V. Conclusion

Therefore, tolerances are established for residues of acibenzolar-S-methyl benzo(1,2,3)thiadiazole-7-carbothioic acid-S-methyl ester, including its metabolites and degradates, in or on onion, bulb, subgroup 3-07A at 0.1 ppm; and vegetable, cucurbit, group 9 at 2.0 ppm. Compliance with the specified tolerance levels is to be determined by measuring only those acibenzolar-S-methyl residues convertible to benzo(1,2,3)thiadiazole-7-carboxylic acid (CGA-210007), expressed as the stoichiometric equivalent of acibenzolar-S-methyl, in or on the commodity.

VI. Statutory and Executive Order Reviews

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

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

This final rule directly regulates growers, food processors, food handlers, and food retailers, not States or tribes, nor does this action alter the relationships or distribution of power and responsibilities established by Congress in the preemption provisions of section 408(n)(4) of FFDCA. As such, the Agency has determined that this action will not have a substantial direct effect on States or tribal governments, on the relationship between the national government and the States or tribal governments, or on the distribution of power and responsibilities among the various levels of government or between the Federal Government and Indian tribes. Thus, the Agency has determined that Executive Order 13132, entitled *Federalism* (64 FR 43255, August 10, 1999) and Executive Order 13175, entitled *Consultation and Coordination with Indian Tribal Governments* (65 FR 67249, November 9, 2000) do not apply to this final rule. In addition, this final rule does not impose any enforceable duty or contain any unfunded mandate as described under Title II of the Unfunded Mandates Reform Act of 1995 (UMRA) (Public Law 104–4).

This action does not involve any technical standards that would require Agency consideration of voluntary consensus standards pursuant to section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113, section 12(d) (15 U.S.C. 272 note).

VII. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report 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 United States prior to publication of this final rule in the **Federal Register**. This final rule is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 180

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

Dated: May 15, 2009.

Lois Rossi,

Director, Registration Division, Office of Pesticide Programs.

■ Therefore, 40 CFR chapter I is amended as follows:

PART 180—[AMENDED]

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

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

■ 2. Section 180.561 is amended by revising paragraph (a) and paragraph (b) in the table by removing the entry for onion, bulb to read as follows:

§ 180.561 Acibenzolar-S-methyl; tolerances for residues.

(a) *General.* (1) Tolerances are established for residues of acibenzolar-S-methyl, benzo(1,2,3)thiadiazole-7-carbothioic acid-S-methyl ester, in or on the following raw agricultural commodities:

Commodity	Parts per million
Banana[1]	0.1
Spinach	1.0
Tomato, paste	3.0
Vegetable, brassica, leafy, group 5	1.0
Vegetable, fruiting, group 8	1.0
Vegetable, leafy, group 4	0.25

[1]There are no United States registrations for banana.

(2) Tolerances are established for residues of acibenzolar-S-methyl, benzo(1,2,3)thiadiazole-7-carbothioic acid-S-methyl ester, including its metabolites and degradates, in or on the commodities in the table below. Compliance with the tolerance levels specified below is to be determined by measuring only those acibenzolar-S-methyl residues convertible to benzo(1,2,3)thiadiazole-7-carboxylic acid (CGA-210007), expressed as the stoichiometric equivalent of acibenzolar-S-methyl, in or on the commodity.

Commodity	Parts per million
Onion, bulb, subgroup 3–07A	0.1
Vegetable, cucurbit, group 9	2.0

* * * * *

[FR Doc. E9–12142 Filed 5–22–09; 8:45 am]

BILLING CODE 6560–50–S

Proposed Rules

Federal Register

Vol. 74, No. 99

Tuesday, May 26, 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–2009–0477; Directorate Identifier 2008–NM–191–AD]

RIN 2120–AA64

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

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

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: The FAA proposes to supersede an existing airworthiness directive (AD) that applies to certain Boeing Model 747 series airplanes. The existing AD currently requires repetitive inspections to detect cracks in various areas of the fuselage internal structure, and related investigative/corrective actions if necessary. This proposed AD would require additional repetitive inspections for cracking of certain fuselage structure, and related investigative/corrective actions if necessary. This proposed AD results from fatigue tests and analysis by Boeing that identified areas of the fuselage where fatigue cracks can occur. We are proposing this AD to prevent the loss of the structural integrity of the fuselage, which could result in rapid depressurization of the airplane.

DATES: We must receive comments on this proposed AD by July 10, 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 proposed 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*. You may review copies of the referenced 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.

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 proposed 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: Ivan Li, Aerospace Engineer, Airframe Branch, ANM–120S, FAA, Seattle Aircraft Certification Office, 1601 Lind Avenue, SW., Renton, Washington 98057–3356; telephone (425) 917–6437; fax (425) 917–6590.

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to send any written relevant data, views, or arguments about this proposed AD. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2009–0477; Directorate Identifier 2008–NM–191–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of this proposed AD. We will consider all comments received by the closing date and may amend this proposed 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 proposed AD.

Discussion

On September 26, 2005, we issued AD 2005–20–30, amendment 39–14327 (70 FR 59252, October 12, 2005), for certain Boeing Model 747 series airplanes. That AD requires repetitive inspections to detect cracks in various areas of the fuselage internal structure, and related investigative/corrective actions if necessary. That AD resulted from fatigue tests and analysis by Boeing that identified areas of the fuselage where fatigue cracks can occur. We issued that AD to prevent the loss of the structural integrity of the fuselage, which could result in rapid depressurization of the airplane.

Actions Since Existing AD Was Issued

Since we issued AD 2005–20–30, Boeing has conducted an additional analysis that shows that Section 41 fuselage frames in the areas attached to the upper deck floor beams are also prone to fatigue cracking. Cracking of the frames was found on the fatigue test airplane at about 40,000 total pressure cycles. As a result, we have determined that additional inspections are necessary, as specified in the service information described below.

Relevant Service Information

We have reviewed Boeing Alert Service Bulletin 747–53A2349, Revision 3, dated October 2, 2008 (''the service bulletin''). In AD 2005–20–30, we referred to Boeing Alert Service Bulletin 747–53A2349, Revision 1, dated October 12, 2000; and Boeing Service Bulletin 747–53A2349, Revision 2, dated April 3, 2003; as the appropriate sources of service information for doing the actions required by that AD. Revision 3 of the service bulletin retains the procedures from Revision 2, revises some airplane groups, and adds the repetitive inspections listed in the table titled ''New Service Bulletin Procedures.''

NEW SERVICE BULLETIN PROCEDURES

Revision 3 of the service bulletin adds procedures for repetitive detailed inspections for cracking of these areas specified in the service bulletin—	For airplanes identified as these groups in Revision 3 of the service bulletin—
Additional inspections in Area 1: Fuselage frames at body stations 260–520 in areas where the upper deck floor beams are attached (Figure 11 of the Accomplishments Instructions of the service bulletin).	1 through 7 inclusive.
Additional inspections in Area 6: Fuselage frames at body stations 400–500 in areas above the Main Entry Door 1 cutouts, from the upper chord of the upper deck floor beams to Stringer 8 (Figure 12 of the Accomplishment Instructions of the service bulletin).	6 and 7.

The service bulletin specifies that the compliance time for the inspections of additional areas is before 22,000 total flight cycles or within 1,000 flight cycles after the date on the service bulletin, whichever occurs later. The service bulletin also specifies repeating the inspections at intervals not to exceed 3,000 flight cycles. The service bulletin specifies to repair any crack or to contact Boeing for repair instructions.

Accomplishing the actions specified in the service information is intended to adequately address the unsafe condition.

FAA's Determination and Requirements of the Proposed AD

We have evaluated all pertinent information and identified an unsafe condition that is likely to develop on other airplanes of the same type design. For this reason, we are proposing this AD, which would supersede AD 2005–20–30 and would retain the requirements of the existing AD. This proposed AD would also require accomplishing the additional actions specified in Boeing Alert Service Bulletin 747–53A2349, Revision 3, dated October 2, 2008, described previously.

Change to Existing AD

This proposed AD would retain all requirements of AD 2005–20–30. Since AD 2005–20–30 was issued, the AD format has been revised, and certain paragraphs have been rearranged. As a result, the corresponding paragraph identifiers have changed in this proposed AD, as listed in the following table:

REVISED PARAGRAPH IDENTIFIERS

Requirement in AD 2005–20–30	Corresponding requirement in this proposed AD
paragraph (f)	paragraph (g).
paragraph (g)	paragraph (h).
paragraph (h)	paragraph (i).
paragraph (i)	paragraph (j).
paragraph (j)	paragraph (k).
paragraph (k)	paragraph (l).

Costs of Compliance

There are about 209 airplanes of the affected design in the worldwide fleet. The following table provides the estimated costs for U.S. operators to comply with this proposed AD. The average labor rate is $80 per work hour.

ESTIMATED COSTS

Action	Work hours	Cost per airplane, per inspection cycle	Number of U.S.-registered airplanes	Fleet cost
Inspections (required by AD 2005–20–30)	130	$10,400	69	$717,600
Additional inspections in Area 1 (new proposed action)	6	480	69	33,120
Additional inspections in Area 6 (new proposed action)	1	80	69	5,520

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. *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.

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 removing amendment 39–14327 (70 FR 59252, October 12, 2005) and adding the following new AD:

Boeing: Docket No. FAA–2009–0477; Directorate Identifier 2008-NM–191-AD.

Comments Due Date

(a) The FAA must receive comments on this AD action by July 10, 2009.

Affected ADs

(b) This AD supersedes AD 2005–20–30.

Applicability

(c) This AD applies to Boeing Model 747–100, 747–100B, 747–100B SUD, 747–200B, 747–300, 747SP, and 747SR series airplanes; certificated in any category; identified in Boeing Service Bulletin 747–53A2349, Revision 3, dated October 2, 2008.

Subject

(d) Air Transport Association (ATA) of America Code 53: Fuselage.

Unsafe Condition

(e) This AD results from fatigue tests and analysis by Boeing that identified areas of the fuselage where fatigue cracks can occur. We are issuing this AD to prevent the loss of the structural integrity of the fuselage, which could result in rapid depressurization of the airplane.

Compliance

(f) 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 Requirements of AD 2002–10–10

(Excluding Upper Deck Floor Beams)

Repetitive Inspections

(g) Prior to the accumulation of 22,000 total flight cycles, or within 1,000 flight cycles after June 11, 1993 (the effective date of AD 93–08–12, amendment 39–8559, which was superseded by AD 2002–10–10), whichever occurs later, unless accomplished previously within the last 2,000 flight cycles; and thereafter at intervals not to exceed 3,000 flight cycles: Perform an internal detailed inspection to detect cracks in the areas of the fuselage internal structure specified in paragraphs (g)(1) through (g)(6) of this AD; in accordance with Boeing Service Bulletin 747–53–2349, dated June 27, 1991; Boeing Alert Service Bulletin 747–53A2349, Revision 1, dated October 12, 2000; Boeing Service Bulletin 747–53A2349, Revision 2, dated April 3, 2003; or Boeing Alert Service Bulletin 747–53A2349, Revision 3, dated October 2, 2008. After the effective date of this AD, only Revision 3 of Boeing Alert Service Bulletin 747–53A2349 may be used. Continue doing the inspections until the inspections required by paragraph (j) of this AD are done.

(1) Section 42 upper lobe frames.
(2) Section 46 lower lobe frames.
(3) Section 42 lower lobe frames.
(4) Main entry door cutouts.
(5) Section 41 body station 260, 340, and 400 bulkheads.
(6) Main entry doors.

Note 1: 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.''

(h) Prior to the accumulation of 25,000 total flight cycles, or within 1,000 flight cycles after June 11, 1993, whichever is later, unless already done within the last 2,000 flight cycles; and thereafter at intervals not to exceed 3,000 flight cycles: Do an internal detailed inspection to detect cracks in the Section 46 upper lobe frames, in accordance with Boeing Service Bulletin 747–53–2349, dated June 27, 1991; Boeing Alert Service Bulletin 747–53A2349, Revision 1, dated October 12, 2000; Boeing Service Bulletin 747–53A2349, Revision 2, dated April 3, 2003; or Boeing Alert Service Bulletin 747–53A2349, Revision 3, dated October 2, 2008. After the effective date of this AD, only Revision 3 of Boeing Alert Service Bulletin 747–53A2349 may be used.

Repair of Cracks Detected During Paragraph (g) or (h) Inspections

(i) Before further flight, repair any cracks detected during the inspections done per paragraph (g) or (h) of this AD by doing the actions specified in paragraph (i)(1) or (i)(2) of this AD, as applicable.

(1) Repair in accordance with a method approved by the Manager, Seattle Aircraft Certification Office (ACO), FAA; or using a method approved in accordance with paragraph (p) of this AD.

(2) Repair in accordance with Boeing Service Bulletin 747–53A2349, Revision 2, dated April 3, 2003; or Boeing Alert Service Bulletin 747–53A2349, Revision 3, dated October 2, 2008. After the effective date of this AD, only Revision 3 of Boeing Alert Service Bulletin 747–53A2349 may be used. Where either revision of the service bulletin specifies to contact Boeing for repair instructions, repair in accordance with a method approved by the Manager, Seattle ACO; or using a method approved in accordance with paragraph (p) of this AD.

Restatement of Requirements of AD 2005–20–30

Repetitive Inspections

(j) Do an internal detailed inspection to detect cracking in the areas of the fuselage internal structure specified in paragraphs (j)(1), (j)(2), and (j)(3) of this AD, and internal and external detailed inspections of the areas specified in paragraphs (j)(4), (j)(5), (j)(6), and (j)(7) of this AD. Do the inspections in accordance with Boeing Service Bulletin 747–53A2349, Revision 2, dated April 3, 2003; or Boeing Alert Service Bulletin 747–53A2349, Revision 3, dated October 2, 2008. After the effective date of this AD, only Revision 3 of Boeing Alert Service Bulletin 747–53A2349 may be used. Do the inspections at the applicable time specified in paragraph (k) of this AD. Accomplishment of these inspections terminates the requirements of paragraph (g) of this AD.

(1) Section 42 upper lobe frames.
(2) Section 46 lower lobe frames.
(3) Section 42 lower lobe frames.
(4) Main entry door cutouts.
(5) Nose wheel well bulkheads, sidewall panels, and Station (STA) 360 and 380 floor beams. These areas include Section 41 body station 260, 340, and 400 bulkheads.
(6) Main entry doors.
(7) Main electronics bay access door cutout.

(k) Do the inspections required by paragraph (j) of this AD at the applicable time specified in paragraph (k)(1), (k)(2), or (k)(3) of this AD. Repeat the inspections thereafter at intervals not to exceed 3,000 flight cycles.

(1) For airplanes on which the inspections required by paragraphs (g)(1), (g)(2), (g)(3), (g)(4), and (g)(6) of this AD have been done before November 16, 2005 (the effective date of AD 2005–20–30), but the inspections required by paragraphs (j)(5) and (j)(7) of this AD have not been done: Within 3,000 flight cycles since accomplishment of the most recent inspection required by paragraphs (g)(1), (g)(2), (g)(3), (g)(4), and (g)(6) of this AD, except that the inspections specified in paragraphs (j)(5) and (j)(7) of this AD may be done within 3,000 flight cycles since accomplishment of the most recent inspection required by paragraphs (g)(1), (g)(2), (g)(3), (g)(4), and (g)(6) of this AD, or within 1,000 flight cycles after November 16, 2005, whichever is later.

(2) For airplanes on which the inspections required by paragraphs (j)(5) and (j)(7) have been done before November 16, 2005: Within 3,000 flight cycles since accomplishment of the most recent inspection required by paragraphs (j)(5) and (j)(7) of this AD, or within 1,000 flight cycles after November 16, 2005, whichever is later.

(3) For airplanes on which the inspections required by paragraph (g) of this AD have not been done before November 16, 2005: Prior to the accumulation of 22,000 total flight cycles, or within 1,000 flight cycles after November 16, 2005, whichever is later.

Repair of Cracks Detected During Paragraph (j) Inspection

(l) Before further flight, repair any cracking found during any inspection required by paragraph (j) of this AD in accordance with Boeing Service Bulletin 747–53A2349, Revision 2, dated April 3, 2003; or Boeing Alert Service Bulletin 747–53A2349, Revision 3, dated October 2, 2008. After the effective date of this AD, only Revision 3 of Boeing Alert Service Bulletin 747–53A2349 may be used. Where any revision of the service bulletin specifies to contact Boeing for repair instructions, repair in accordance with a method approved by the Manager, Seattle ACO; or using a method approved in accordance with paragraph (p) of this AD.

New Requirements of This AD

Inspections and Repair

(m) Do initial and repetitive detailed inspections for cracking in the areas specified in Table 1 of this AD using applicable internal and external detailed inspection methods; and repair all cracks, by doing all the applicable actions in accordance with the Accomplishment Instructions of Boeing Alert Service Bulletin 747–53A2349, Revision 3, dated October 2, 2008, except as required by paragraph (n) of this AD. Do the initial and repetitive inspections at the times specified in paragraph 1.E., ''Compliance,'' of the service bulletin, except as required by paragraph (o) of this AD. Repair all cracks before further flight after detection.

TABLE 1—ADDITIONAL INSPECTIONS

Inspect the addition portion of area 1 and area 6 as specified in Boeing Alert Service Bulletin 747–53A2349, Revision 3, dated October 2, 2008 (''the service bulletin'')—	For airplanes identified as these groups in the service bulletin—
In Area 1: Fuselage frames at body stations 260–520 in areas where the upper deck floor beams are attached (Figure 11 of the Accomplishments Instructions of the service bulletin).	1 through 7 inclusive.
In Area 6: Fuselage frames at body stations 400–500 in areas above the Main Entry Door 1 cutouts, from the upper chord of the upper deck floor beams to Stringer 8 (Figure 12 of the Accomplishment Instructions of the service bulletin).	6 and 7.

Exceptions to Certain Procedures

(n) If any crack is found during any inspection required by paragraph (m) of this AD, and Boeing Alert Service Bulletin 747–53A2349, Revision 3, dated October 2, 2008, specifies to contact Boeing for appropriate action: Before further flight, repair the crack using a method approved in accordance with the procedures specified in paragraph (p) of this AD.

(o) Where Boeing Alert Service Bulletin 747–53A2349, Revision 3, dated October 2, 2008, specifies a compliance time after the date on Boeing Alert Service Bulletin 747–53A2349, Revision 3, dated October 2, 2008, this AD requires compliance within the specified compliance time after the effective date of this AD.

Alternative Methods of Compliance (AMOCs)

(p)(1) The Manager, Seattle 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:* Ivan Li, Aerospace Engineer, Airframe Branch, ANM–120S, FAA, Seattle Aircraft Certification Office, 1601 Lind Avenue, SW., Renton, Washington 98057–3356; telephone (425) 917–6437; 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.

(3) AMOCs approved previously in accordance with AD 2005–20–30 are approved as AMOCs with the corresponding provisions of this AD.

(4) An AMOC that provides an acceptable level of safety may be used for any repair required by this AD, if it is approved by an Authorized Representative for the Boeing Commercial Airplanes Delegation Option Authorization Organization who has been authorized by the Manager, Seattle ACO, to make those findings. For a repair method to be approved, the repair must meet the certification basis of the airplane, and the approval must specifically refer to this AD.

Issued in Renton, Washington, on May 15, 2009.

Ali Bahrami,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. E9–12111 Filed 5–22–09; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2009–0476; Directorate Identifier 2008–NM–188–AD]

RIN 2120–AA64

Airworthiness Directives; Boeing Model 707 Airplanes, and Model 720 and 720B Series Airplanes

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

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: The FAA proposes to supersede an existing airworthiness directive (AD) that applies to certain Boeing Model 707 airplanes, and Model 720 and 720B series airplanes. The existing AD currently requires repetitive detailed inspections to detect cracks and corrosion on any existing repairs and at certain body stations (STA) of the visible surfaces of the wing to body terminal fittings including the web, flanges, and ribs; and applicable related investigative and corrective actions. This proposed AD would retain the requirements of the existing AD and would require repetitive ultrasonic inspections to detect any stress corrosion cracks within the outboard flange of the left and right body terminal fittings at STA 820, and related investigative and corrective actions if necessary. This proposed AD would also provide for an optional terminating action for the repetitive inspections. This proposed AD also adds two airplanes to the applicability. This proposed AD results from reports of cracks found in the wing to body terminal fittings during routine inspections. We are proposing this AD to detect and correct cracks and corrosion in the body terminal fittings above and below the floor, which could cause loss of support for the wing and could adversely affect the structural integrity of the airplane.

DATES: We must receive comments on this proposed AD by July 10, 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*. You may review copies of the referenced 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.

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 proposed 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: Berhane Alazar, Aerospace Engineer, Airframe Branch, ANM–120S, FAA, Seattle Aircraft Certification Office, 1601 Lind Avenue, SW., Renton, Washington 98057–3356; telephone (425) 917–6577; fax (425) 917–6590.

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to send any written relevant data, views, or arguments about this proposed AD. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2009–0476; Directorate Identifier 2008–NM–188–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of this proposed AD. We will consider all comments received by the closing date and may amend this proposed 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 proposed AD.

Discussion

On August 6, 2008, we issued AD 2008–17–10, amendment 39–15648 (73 FR 50703, August 28, 2008), for certain Boeing Model 707 airplanes, and Model 720 and 720B series airplanes. That AD requires repetitive detailed inspections to detect cracks and corrosion on any existing repairs and at certain body stations (STA) of the visible surfaces of the wing to body terminal fittings including the web, flanges and ribs; and applicable related investigative and corrective actions. That AD resulted from reports of cracks found in the wing to body terminal fittings during routine inspections. We issued that AD to detect and correct cracks and corrosion in the body terminal fittings, which could cause loss of support for the wing and could adversely affect the structural integrity of the airplane.

Relevant Service Information

We have reviewed Boeing 707 Alert Service Bulletin A3524, Revision 1, dated September 18, 2008. (AD 2008–17–10 refers to Boeing 707 Special Attention Service Bulletin 3524, dated July 18, 2007, as the appropriate source of service information for accomplishing the required actions in that AD.) Revision 1 of this service bulletin adds procedures, for certain airplanes, to do repetitive ultrasonic inspections for stress corrosion cracks within the outboard flange of the left and right body terminal fittings at STA 820, and if necessary, related investigative and corrective actions. The related investigative action is an inspection to determine whether the modification or repair meets the specifications of Boeing 707/720 Service Bulletin 2912, Revision 1, dated March 13, 1970. The corrective action is contacting Boeing for repair instructions. Revision 1 of Boeing 707 Alert Service Bulletin A3524 also adds two airplanes to the effectivity.

Boeing 707 Alert Service Bulletin A3524, Revision 1, refers to Boeing 707/720 Service Bulletin 2912, Revision 1, dated March 13, 1970, as an additional source of service information for doing certain inspections and repairs.

FAA's Determination and Requirements of the Proposed AD

We have evaluated all pertinent information and identified an unsafe condition that is likely to develop on other airplanes of the same type design. For this reason, we are proposing this AD, which would supersede AD 2008–17–10 and would retain the requirements of the existing AD. This proposed AD would also add, for certain airplanes, repetitive ultrasonic inspections to detect any stress corrosion cracks within the outboard flange of the left and right body terminal fittings at STA 820, and related investigative and corrective actions if necessary. This proposed AD would also add two airplanes to the applicability.

Costs of Compliance

There are about 128 airplanes of the affected design in the worldwide fleet. The following table provides the estimated costs for U.S. operators to comply with this proposed AD.

ESTIMATED COSTS

Action	Work hours	Average labor rate per hour	Cost per airplane	Number of U.S.-registered airplanes	Fleet cost
Inspections (required by AD 2008–17–10).	20	$80	$1,600 per inspection cycle.	11	$17,600 per inspection cycle.
Inspections (new proposed action).	20 to 30, depending on group.	80	$1,600 to $2,400 per inspection cycle.	Up to 13	Up to $31,200 per inspection cycle.

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. 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.

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 removing amendment 39–15648 (73 FR 50703, August 28, 2008) and adding the following new AD:

Boeing: Docket No. FAA–2009–0476; Directorate Identifier 2008–NM–188–AD.

Comments Due Date

(a) The FAA must receive comments on this AD action by July 10, 2009.

Affected ADs

(b) This AD supersedes AD 2008–17–10.

Applicability

(c) This AD applies to Model 707–100 long body, –200, –100B long body, and –100B short body series airplanes; Model 707–300, –300B, –300C, and –400 series airplanes; and Model 720 and 720B series airplanes; certificated in any category; as identified in Boeing 707 Alert Service Bulletin A3524, Revision 1, dated September 18, 2008.

Subject

(d) Air Transport Association (ATA) of America Code 57: Wings.

Unsafe Condition

(e) This AD results from new findings of cracks found in the wing to body terminal fittings during routine inspections. We are issuing this AD to detect and correct cracks and corrosion in the body terminal fittings above and below the floor, which could cause loss of support for the wing and could adversely affect the structural integrity of the airplane.

Compliance

(f) 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 Requirements of AD 2008–17–10

Inspections and Corrective Actions

(g) For airplanes identified in Boeing 707 Special Attention Service Bulletin 3524, dated July 18, 2007: Within 24 months after October 2, 2008 (the effective date of AD 2008–17–10), do detailed inspections and applicable related investigative and corrective actions, by accomplishing all the actions specified in the Accomplishment Instructions of Boeing 707 Special Attention Service Bulletin 3524, dated July 18, 2007; or Boeing 707 Alert Service Bulletin A3524, Revision 1, dated September 18, 2008; except as provided by paragraph (h) of this AD. After the effective date of this AD, use only Boeing 707 Alert Service Bulletin A3524, Revision 1, dated September 18, 2008. Repeat the detailed inspections thereafter at intervals not to exceed 24 months. Do all applicable related investigative and corrective actions before further flight.

(h) If any crack or corrosion is found during any inspection required by paragraph (g) of this AD, and Boeing 707 Special Attention Service Bulletin 3524, dated July 18, 2007; or Boeing 707 Alert Service Bulletin A3524, Revision 1, dated September 18, 2008; specifies to contact Boeing for appropriate action: Before further flight, repair the terminal fittings using a method approved in accordance with the procedures specified in paragraph (o) of this AD.

No Information Submission

(i) Although Boeing 707 Special Attention Service Bulletin 3524, dated July 18, 2007; and Boeing 707 Alert Service Bulletin A3524, Revision 1, dated September 18, 2008; specify to submit information to the manufacturer, this AD does not include that requirement.

New Requirements of This AD

Inspections

(j) For Group 1 and Group 2 airplanes identified in Boeing 707 Alert Service Bulletin A3524, Revision 1, dated September 18, 2008, on which a modification or repair was done in accordance with Boeing 707/720 Service Bulletin 2912, Revision 1, dated March 13, 1970: At the later of the times specified in paragraphs (j)(1) and (j)(2) of this AD, do an ultrasonic inspection to detect any stress corrosion cracks within the outboard flange of the left and right body terminal fittings at body station (STA) 820, and all applicable related investigative and corrective actions, by accomplishing all the actions specified in the Accomplishment Instructions of Boeing 707 Alert Service Bulletin A3524, Revision 1, dated September 18, 2008, except as provided by paragraph (m) of this AD. Repeat the ultrasonic inspection thereafter at intervals not to exceed 24 months or 2,000 flight cycles, whichever occurs first. Do all applicable related investigative and corrective actions before further flight.

(1) Within 24 months or 2,000 flight cycles after the effective date of this AD, whichever occurs first.

(2) Within 24 months or 2,000 flight cycles after doing the repair or modification, whichever occurs first.

(k) For Group 3 and 4 airplanes identified in Boeing 707 Alert Service Bulletin A3524, Revision 1, dated September 18, 2008: Within 2,000 flight cycles or 24 months after the effective date of this AD, whichever occurs first, do an ultrasonic inspection to detect any stress corrosion cracks within the outboard flange of the left and right body terminal fittings at STA 820, and all applicable corrective actions, by accomplishing all the actions specified in the Accomplishment Instructions of Boeing 707 Alert Service Bulletin A3524, Revision 1, dated September 18, 2008, except as provided by paragraph (m) of this AD. Repeat the ultrasonic inspection thereafter at intervals not to exceed 24 months or 2,000 flight cycles, whichever occurs first. Do all applicable corrective actions before further flight.

(l) For Group 4 airplanes identified in Boeing 707 Alert Service Bulletin A3524, Revision 1, dated September 18, 2008: Within 24 months after the effective date of this AD, do detailed inspections for corrosion and cracking of the body terminal fittings at STA 820, and all applicable related investigative and corrective actions, by accomplishing all the actions specified in the Accomplishment Instructions of Boeing 707 Alert Service Bulletin A3524, Revision 1, dated September 18, 2008, except as provided by paragraph (m) of this AD. Repeat the detailed inspections thereafter at intervals not to exceed 24 months. Do all applicable related investigative and corrective actions before further flight.

Exception to Certain Procedures

(m) If any crack or corrosion is found during any inspection required by paragraph (j), (k), or (l) of this AD, and Boeing 707 Alert Service Bulletin A3524, Revision 1, dated September 18, 2008, specifies to contact Boeing for appropriate action: Before further flight, repair the terminal fittings using a method approved in accordance with the procedures specified in paragraph (o) of this AD.

Note 1: Boeing 707 Alert Service Bulletin A3524, Revision 1, dated September 18, 2008, refers to Boeing 707/720 Service Bulletin 2912, Revision 1, dated March 13, 1970, as an additional source of service information for doing certain inspections and repairs.

Optional Terminating Action

(n) Replacing a body terminal fitting with a fitting made from 7075–T73 material, using a method approved in accordance with the procedures specified in paragraph (o) of this AD, terminates the repetitive inspections required by this AD for that fitting only.

Alternative Methods of Compliance (AMOCs)

(o)(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: Berhane Alazar, Aerospace Engineer, Airframe Branch, ANM–120S, FAA, Seattle Aircraft Certification Office, 1601 Lind Avenue, SW., Renton, Washington 98057–3356; telephone (425) 917–6577; 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.

(3) An AMOC that provides an acceptable level of safety may be used for any repair required by this AD, if it is approved by an Authorized Representative for the Boeing Commercial Airplanes Delegation Option Authorization Organization who has been authorized by the Manager, Seattle ACO, to make those findings. For a repair method to be approved, the repair must meet the certification basis of the airplane, and the approval must specifically refer to this AD.

Issued in Renton, Washington, on May 15, 2009.

Ali Bahrami,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. E9–12112 Filed 5–22–09; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Chapter I

[Docket No. PL09–4–000]

Smart Grid Policy; Notice of Extension of Time

May 21, 2009.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of extension of time.

SUMMARY: On March 19, 2009, the Federal Energy Regulatory Commission (Commission) issued a Proposed Policy Statement and Action Plan that, among other things, proposed an interim rate policy to encourage the development of smart grid systems. On May 19, 2009, the Commission issued a Notice Requesting Supplemental Comments regarding rate recovery for certain smart grid investments. The Commission is extending the date for filing these supplemental comments.

DATES: Comments are due June 2, 2009.

FOR FURTHER INFORMATION CONTACT:

Ray Palmer (Technical Information), Office of Energy Policy and Innovation, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–6569 .

Elizabeth Arnold (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–8818.

SUPPLEMENTARY INFORMATION:

On March 19, 2009, the Federal Energy Regulatory Commission (Commission) issued a Proposed Policy Statement and Action Plan (Proposed Policy Statement) in the above-captioned proceeding that, among other things, proposed an interim rate policy to encourage the development of Smart Grid systems.[1] On May 19, 2009, the Commission issued a notice in this docket seeking supplemental comments regarding rate recovery for certain grid investments.[2] The Commission is hereby extending the comment deadline established in the May 19 Notice.

By this instant notice, the date for filing supplemental comments is extended to and including June 2, 2009.

Kimberly D. Bose,

Secretary.

[FR Doc. E9–12243 Filed 5–22–09; 8:45 am]

BILLING CODE 6717–01–P

[1] *Smart Grid Policy,* 126 FERC ¶ 61,253 (2009). As the Proposed Policy Statement described, Smart Grid advancements will apply digital technologies to the electric transmission system and enable real-time coordination of information from various resources to bring new efficiencies to the grid. *Id.* P 1.

[2] *Smart Grid Policy,* 127 FERC ¶ 61,139 (2009) (May 19 Notice).

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 110

[Docket No. USCG–2008–1232]

RIN 1625–AA01

Anchorages; New and Revised Anchorages in the Captain of the Port Portland, OR, Area of Responsibility

AGENCY: Coast Guard, DHS.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Coast Guard proposes the establishment of a new anchorage, modification of existing anchorages, and revision of the regulations governing anchorages in the Captain of the Port Portland, Oregon, area of responsibility. These changes are necessary to ensure sufficient anchorage opportunities in that area, and to clarify the locations of those anchorage opportunities. In addition, the changes will help prevent conflicts with navigable channels and other uses of anchorage waters.

DATES: Comments and related material must be received by the Coast Guard on or before July 27, 2009. Requests for public meetings must be received by the Coast Guard on or before June 25, 2009.

ADDRESSES: You may submit comments identified by docket number USCG–2008–1232 using any 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.

To avoid duplication, please use only one of these four methods. See the ''Public Participation and Request for Comments'' portion of the **SUPPLEMENTARY INFORMATION** section below for instructions on submitting comments.

FOR FURTHER INFORMATION CONTACT: If you have questions on this proposed rule, call or e-mail MST1 Jaime Sayers, Waterways Management Branch, Coast Guard Sector Portland, telephone 503–240–9300, e-mail: *Jaime.A.Sayers@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:

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.

Submitting Comments

If you submit a comment, please include the docket number for this rulemaking (USCG–2008–1232), 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 (via *http://www.regulations.gov*) or by fax, mail, or hand delivery, but please use only one of these means. If you submit a comment online via *http://www.regulations.gov,* it will be considered received by the Coast Guard when you successfully transmit the comment. If you fax, hand deliver, or mail your comment, it will be considered as having been received by the Coast Guard when it is received at the Docket Management Facility. We recommend that you include your name and a mailing address, an e-mail address, or a telephone number in the body of your document so that we can contact you if we have questions regarding your submission.

To submit your comment online, go to *http://www.regulations.gov,* select the Advanced Docket Search option on the right side of the screen, insert ''USCG–2008–1232'' in the Docket ID box, press Enter, and 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 the rule based on your comments.

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,* select the Advanced Docket Search option on the right side of the screen, insert USCG–2008–1232 in the Docket ID box, press Enter, and then click on the item in the Docket ID column. You may also visit the Docket Management Facility in Room W12–140 on the ground floor of the Department of Transportation West Building, 1200 New Jersey Avenue, SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. We have an agreement with the Department of Transportation to use the Docket Management Facility.

Privacy Act

Anyone can search the electronic form of comments received into any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, etc.). You may review a Privacy Act notice regarding our public dockets in the January 17, 2008, issue of the **Federal Register** (73 FR 3316).

Public Meeting

We do not now plan to hold a public meeting. But, you may submit a request for one on or before June 25, 2009 using one of the four methods specified under **ADDRESSES**. Please explain why you believe a public meeting would be beneficial. If we determine that a public meeting would aid this rulemaking, we will hold one at a time and place announced by a later notice in the **Federal Register**.

Background and Purpose

The establishment of a new anchorage, modification of existing anchorages, and revision of the regulations governing anchorages contained in this rule are necessary to ensure sufficient anchorage opportunities in the Captain of the Port Portland, Oregon, area of responsibility, and ensure that the locations of those opportunities are clear. In addition, the changes will help prevent conflicts with navigable channels and other uses of anchorage waters. Currently, there are insufficient anchorage opportunities in the Captain of the Port Portland, Oregon, area of responsibility, and many of them conflict with navigable channels and other uses of the anchorage waters.

Discussion of Proposed Rule

The proposed rule would revise the following anchorages as noted. The Astoria North Anchorage would be revised to provide additional anchoring area and add an additional area to accommodate the swing of vessels. The Astoria South Anchorage would be revised to ensure that anchored vessels are clear of the navigable channel and that the anchorage correlates with current NOAA navigational charts. The Longview Anchorage would be revised to move it out of the navigational channel and expand it to account for vessel swing. The Kalama Anchorage would be revised to provide additional anchoring area and add an additional area to accommodate the swing of vessels. The Woodland Anchorage would be revised to ensure the anchorage correlates with current NOAA navigational charts. The Henrici Bar Anchorage would be revised to move it out of the navigational channel. The Willow Bar Anchorage would be renamed the Vancouver Lower Anchorage and revised to consolidate the Willow Bar Anchorage and the anchorage areas off of the Morgan Bar. The Kelley Point Anchorage would be revised to ensure the anchorage correlates with current NOAA navigational charts. The Hayden Island Anchorage would be renamed the Upper Vancouver Anchorage and revised to expand the anchorage and move the anchorage out of the navigational channel.

The proposed rule would also create a new anchorage called the Cottonwood Island Anchorage near Cottonwood Island.

The regulations governing the anchorages would be amended to remove provisions that are no longer necessary, due to changes in the use of the anchorage areas for fishing, and to add a provision to prevent anchoring vessels from entangling underground cables.

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.

Regulatory Planning and Review

This proposed rule is not a significant regulatory action under section 3(f) of Executive Order 12866, Regulatory Planning and Review, and does not require an assessment of potential costs and benefits under section 6(a)(3) of that Order. The Office of Management and Budget has not reviewed it under that Order. The establishment of a new anchorage, modification of existing anchorages, and revision of the regulations governing anchorages do not have any significant costs associated with them.

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.

The Coast Guard certifies under 5 U.S.C. 605(b) that this proposed rule would not have a significant economic impact on a substantial number of small entities. This proposed rule would affect the following entities, some of which might be small entities: The owners or operators of vessels intending to transit or anchor in the Captain of the Port Portland, Oregon, area of responsibility. However, the establishment of a new anchorage, modification of existing anchorages, and revision of the regulations governing anchorages that would result from this rule would have no economic impact on small entities because anchorages can still be transited and used for other maritime activities besides anchoring.

If you think that your business, organization, or governmental jurisdiction qualifies as a small entity and that this rule would have a significant economic impact on it, please submit a comment (see **ADDRESSES**) explaining why you think it qualifies and how and to what degree this rule would economically affect it.

Assistance for Small Entities

Under section 213(a) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121), we want to assist small entities in understanding this proposed rule so that they can better evaluate its effects on them and participate in the rulemaking. If the rule would affect your small business, organization, or governmental jurisdiction and you have questions concerning its provisions or options for compliance, please contact the Waterways Management Branch, Coast Guard Sector, Portland, Oregon, telephone 503–240–9300. The Coast Guard will not retaliate against small entities that question or complain about this proposed rule or any policy or action of the Coast Guard.

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.).

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 proposed rule under that Order and have determined that it does not have implications for federalism.

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 proposed rule would not result in such an expenditure, we do discuss the effects of this rule elsewhere in this preamble.

Taking of Private Property

This proposed 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.

Civil Justice Reform

This proposed rule meets applicable standards in sections 3(a) and 3(b)(2) of Executive Order 12988, Civil Justice Reform, to minimize litigation, eliminate ambiguity, and reduce burden.

Protection of Children

We have analyzed this proposed rule under Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks. This rule is not an economically significant rule and would not create an environmental risk to health or risk to safety that might disproportionately affect children.

Indian Tribal Governments

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

Energy Effects

We have analyzed this proposed rule under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use. We have determined that it is not a ''significant energy action'' under that order because 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.

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

Environment

We have analyzed this proposed rule under Department of Homeland Security Management Directive 023–01 and Commandant Instruction M16475.lD, which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321–4370f), and have made a preliminary determination that this action is one of a category of actions that do not individually or cumulatively have a significant effect on the human environment. A preliminary environmental analysis checklist supporting this determination is available in the docket where indicated under **ADDRESSES**. This proposed rule involves the establishment of a new anchorage, modification of existing anchorages, and revision of the regulations governing anchorages in the Captain of the Port Portland, Oregon, area of responsibility, which are categorically excluded under section

2.B.2 Figure 2–1, paragraph 34(f), of the Instruction. We seek any comments or information that may lead to the discovery of a significant environmental impact from this proposed rule.

List of Subjects in 33 CFR Part 110

Anchorage grounds.

For the reasons discussed in the preamble, the Coast Guard proposes to amend 33 CFR part 110 as follows:

PART 110—ANCHORAGE REGULATIONS

1. The authority citation for part 110 continues to read as follows:

Authority: 33 U.S.C. 471, 1221 through 1236, 2030, 2035, 2071; 33 CFR 1.05–1; Department of Homeland Security Delegation No. 0170.1.

2. Revise § 110.228 to read as follows:

§ 110.228 Columbia River, Oregon and Washington.

(a) *Anchorage grounds*—(1) *Astoria North Anchorage.* An area enclosed by a line beginning northeast of Astoria, Oregon, at latitude 46°12′00.79″ N, longitude 123°49′55.40″ W; thence continuing easterly to latitude 46°12′02.00″ N, longitude 123°49′40.09″ W; thence continuing east-northeasterly to latitude 46°13′14.85″ N, longitude 123°46′27.89″ W; thence continuing south-southeasterly to latitude 46°13′00.56″ N, longitude 123°46′16.65″ W; thence continuing southwesterly to latitude 46°11′51.79″ N, longitude 123°49′18.08″ W; thence continuing west-southwesterly to latitude 46°11′46.27″ N, longitude 123°49′43.48″ W; thence continuing west-southwesterly to latitude 46°11′44.98″ N, longitude 123°49′49.44″ W; thence continuing westerly to latitude 46°11′44.32″ N, longitude 123°49′58.88″ W; thence continuing northeasterly to the point of the beginning.

(2) *Astoria South Anchorage.* An area enclosed by a point beginning east-northeast of Astoria, Oregon, at latitude 46°11′46.95″ N, longitude 123°49′13.04″ W; thence continuing northeasterly to latitude 46°13′02.18″ N, longitude 123°45′54.55″ W; thence continuing to easterly to latitude 46°13′05.90″ N, longitude 123°45′41.55″ W; thence continuing southeasterly to latitude 46°12′55.16″ N, longitude 123°45′34.31″ W; thence continuing southwesterly to latitude 46°12′24.32″ N, longitude 123°46′34.70″ W; thence continuing west-southwesterly to latitude 46°11′37.32″ N, longitude 123°49′03.46″ W; thence continuing north-northwesterly to the point of the beginning.

(3) *Longview Anchorage.* An area enclosed by a line beginning southeast of Longview, Washington, at latitude 46°06′28.69″ N, longitude 122°57′38.33″ W; thence continuing northwesterly to latitude 46°06′41.71″ N, longitude 122°58′01.25″ W; thence continuing westerly to latitude 46°07′22.55″ N, longitude 122°59′00.81″ W; thence continuing westerly to latitude 46°07′36.21″ N, longitude 122°59′19.29″ W; thence continuing southwesterly to latitude 46°07′28.44″ N, longitude 122°59′31.18″ W; thence continuing easterly to latitude 46°07′14.77″ N, longitude 122°59′12.70″ W; thence continuing easterly to latitude 46°06′42.01″ N, longitude 122°58′28.41″ W; thence continuing northeasterly to latitude 46°06′34.27″ N, longitude 122°58′14.21″ W; thence continuing northeasterly to latitude 46°06′32.19″ N, longitude 122°58′08.77″ W; thence continuing northeasterly to latitude 46°06′22.44″ N, longitude 122°57′43.27″ W; thence continuing northeasterly to the point of the beginning.

(4) *Kalama Anchorage.* An area to be enclosed by a line beginning north-northwesterly of Sandy Island at latitude 46°01′20.48″ N, longitude 122°52′04.32″ W; thence continuing east-southeasterly to latitude 46°00′57.73″ N, longitude 122°51′35.14″ W; thence continuing east-southeasterly to latitude 46°00′53.95″ N, longitude 122°51′30.29″ W; thence continuing southeasterly to latitude 46°00′35.10″ N, longitude 122°51′15.37″ W; thence continuing south-southeasterly to latitude 45°59′41.48″ N, longitude 122°50′52.40″ W; thence continuing southwesterly to latitude 45°59′38.65″ N, longitude 122°51′05.97″ W; thence continuing north-northwesterly to latitude 46°00′36.82″ N, longitude 122°51′45.44″ W; thence continuing west-northwesterly to latitude 46°01′24.38″ N, longitude 122°52′21.20″ W; thence continuing northeasterly to the beginning.

(5) *Woodland Anchorage.* An area enclosed by a line beginning northeast of Columbia City, Oregon, at latitude 45°53′55.31″ N, longitude 122°48′17.35″ W; thence continuing easterly to latitude 45°53′57.11″ N, longitude 122°48′02.16″ W; thence continuing south-southeasterly to latitude 45°53′21.16″ N, longitude 122°47′44.28″ W; thence continuing westerly to latitude 45°53′20.16″ N, longitude 122°48′02.37″ W; thence continuing northwesterly to latitude 45°53′41.50″ N, longitude 12°48′13.53″ W; thence continuing northerly to the point of beginning.

(6) *Henrici Bar Anchorage.* An area enclosed by a line beginning west-southwesterly of Bachelor Slough, Washington, at latitude 45°47′24.68″ N, longitude 122°46′49.14″ W; thence continuing east-southeasterly to latitude 45°46′44.95″ N, longitude 122°46′13.23″ W, thence continuing southeasterly to latitude 45°46′25.67″ N, longitude 122°46′00.54″ W; thence continuing south-southeasterly to latitude 45°46′02.69″ N, longitude 122°45′50.32″ N, longitude 122°45′50.32″ W; thence continuing southerly to latitude 45°45′43.66″ N, longitude 122°45′45.33″ W; thence continuing southerly to latitude 45°45′37.52″ N, longitude 122°45′44.99″ W; thence continuing westerly to latitude 45°45′37.29″ N, longitude 122°45′53.06″ W; thence continuing north-northwesterly to latitude 45°46′15.94″ N, longitude 122°46′10.25″ W; thence continuing west-northwesterly to latitude 45°47′20.20″ N, longitude 122°46′59.28″ W; thence continuing easterly to the point of beginning.

(7) *Lower Vancouver Anchorage.* An area enclosed by a line beginning north-northeast of Reeder Point at latitude 45°43′39.18″ N, longitude 122°45′27.54″ W; thence continuing south-southwesterly to latitude 45°41′26.95″ N, longitude 122°46′13.83″ W; thence continuing southerly to latitude 45°40′35.72″ N, longitude 122°46′09.98″ W; thence continuing south-southeasterly to latitude 45°40′23.95″ N, longitude 122°46′04.26″ W; thence continuing west-southwesterly to latitude 45°40′20.68″ N, longitude 122°46′16.07″ W; thence continuing northwesterly to latitude 45°40′32.85″ N, longitude 122°46′21.98″ W; thence continuing north-northwesterly to latitude 45°41′01.03″ N, longitude 122°46′26.85″ W; thence continuing northerly to latitude 45°41′29.07″ N, longitude 12°46′26.15″ W; thence continuing north-northeasterly to latitude 45°43′41.27″ N, longitude 122°45′39.87″ W; thence continuing easterly to the point of the beginning. The Vancouver lower anchorage will then resume slightly further upstream at an area north of Kelly point and will be enclosed by a line starting at latitude 45°40′10.09″ N, longitude 122°45′57.53″ W; thence continuing to southeasterly to latitude 45°39′42.94″ N, longitude 122°45′44.34″ W; thence continuing west-southwesterly to latitude 45°39′40.07″ N, longitude 122°45′56.34″ W; thence continuing northwesterly to latitude 45°40′06.75″ N, longitude 122°46′09.30″ W; thence continuing east-northeasterly to the point of the beginning.

(8) *Kelly Point Anchorage.* An area enclosed by a line beginning northeast of Kelly Point, Oregon, at latitude 45°39′10.32″ N, longitude 122°45′36.45″ W; thence continuing east-southeasterly

to latitude 45°39′02.10″ N, longitude 122°45′21.67″ W; thence continuing east-southeasterly to latitude 45°38′59.15″ N, longitude 122°45′16.38″ W; thence continuing southwesterly to latitude 45°38′51.03″ N, longitude 122°45′25.57″ W; thence continuing westerly to latitude 45°38′51.54″ N, longitude 122°45′26.35″ W; thence continuing northwesterly to latitude 45°39′06.27″ N, longitude 122°45′40.50″ W; thence continuing north-northeasterly to the beginning point.

(9) *Upper Vancouver Anchorage*. An area enclosed by a line beginning north-northeast of Hayden Island at latitude 45°38′43.44″ N, longitude 122°44′39.50″ W; thence continuing northeasterly to 45°38′26.98″ N, longitude 122°43′25.87″ W; thence continuing east-northeasterly to latitude 45°38′17.31″ N, longitude 122°42′54.69″ W; thence continuing easterly to latitude 45°38′12.40″ N, longitude 122°42′43.93″ W; thence continuing east-southeasterly to latitude 45°37′40.53″ N, longitude 122°41′44.08″ W; thence south-southeasterly to latitude 45°37′36.11″ N, longitude 122°41′48.86″ W; thence continuing west-southwesterly to latitude 45°37′52.20″ N, longitude 122°42′19.50″ W; thence continuing west-southwesterly to latitude 45°38′10.75″ N, longitude 122°43′08.89″ W; thence continuing southwesterly to latitude 45°38′18.79″ N, longitude 122°43′44.83″ W; thence continuing westerly to latitude 45°38′41.37″ N, longitude 122°44′40.44″ W; thence continuing northeasterly to the point of beginning.

(10) *Cottonwood Island Anchorage*. An area enclosed by a line beginning west-southwest of Longview, WA at latitude 46°05′56.88″ N, longitude 122°56′53.19″ W; thence continuing easterly to latitude 46°05′14.06″ N, longitude 122°54′45.71″ W; thence continuing east-southeasterly to latitude 46°04′57.12″ N, longitude 122°54′12.41″ W; thence continuing southeasterly to latitude 46°04′37.55″ N, longitude 122°53′45.80″ W; thence continuing southeasterly to latitude 46°04′13.72″ N, longitude 122°53′23.66″ W; thence continuing southeasterly to latitude 46°03′54.94″ N, longitude 122°53′11.81″ W; thence continuing southerly to latitude 46°03′34.96″ N, longitude 122°53′03.17″ W; thence continuing westerly to latitude 46°03′32.06″ W, longitude 122°53′19.68″ N; thence continuing north-northwesterly to latitude 46°03′50.84″ N, longitude 122°53′27.81″ W; thence continuing northwesterly to latitude 46°04′08.10″ N, longitude 122°53′38.70″ W; thence continuing northwesterly to latitude 46°04′29.41″ N, longitude 122°53′58.17″ W; thence continuing north-northwesterly to latitude 46°04′49.89″ N, longitude 122°54′21.57″ W; thence continuing northwesterly to latitude 46°05′06.95″ N, longitude 122°54′50.65″ W; thence continuing northwesterly to latitude 46°05′49.77″ N, longitude 122°56′8.12″ W; thence continuing east-northeasterly to the point of the beginning.

(b) *Regulations*. (1) All designated anchorages are intended for the primary use of deep-draft vessels over 200 feet in length.

(2) If a vessel under 200 feet in length is anchored in a designated anchorage, the master or person in charge of the vessel shall:

(i) Ensure that the vessel is anchored so as to minimize conflict with large, deep-draft vessels utilizing or seeking to utilize the anchorage; and

(ii) Move the vessel out of the area if requested by the master of a large, deep-draft vessel seeking to enter or depart the area or if directed by the Captain of the Port.

(3) Vessels desiring to anchor in designated anchorages shall contact the pilot office that manages that anchorage to request an appropriate position to anchor. Columbia River Bar Pilots manage Astoria North Anchorage and Astoria South Anchorage. Columbia River Pilots manage all designated anchorages upriver from Astoria.

(4) No vessel may occupy a designated anchorage for more than 30 consecutive days without permission from the Captain of the Port.

(5) No vessel being layed-up or dismantled or undergoing major alterations or repairs may occupy a designated anchorage without permission from the Captain of the Port.

(6) No vessel carrying a Cargo of Particular Hazard listed in § 126.10 of this chapter may occupy a designated anchorage without permission from the Captain of the Port.

(7) No vessel in a condition such that it is likely to sink or otherwise become a hazard to the operation of other vessels shall occupy a designated anchorage except in an emergency, and then only for such periods as may be authorized by the Captain of the Port.

(8) Vessels anchoring in Astoria North Anchorage should avoid placing their anchor in the charted cable area.

Dated: May 8, 2009.

J.P. Currier,

Rear Admiral, U.S. Coast Guard, Commander, Thirteenth Coast Guard District.

[FR Doc. E9–12060 Filed 5–22–09; 8:45 am]

BILLING CODE 4910–15–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[Docket No. USCG–2008–1247]

RIN 1625–AA11

Regulated Navigation Area and Safety Zone, Chicago Sanitary and Ship Canal, Romeoville, IL

AGENCY: Coast Guard, DHS.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Coast Guard proposes establishing a regulated navigation area and safety zone on the Chicago Sanitary and Ship Canal near Romeoville, Illinois. This proposed regulated navigation area and safety zone places navigational and operational restrictions on all vessels transiting the navigable waters located adjacent to and over the Army Corps of Engineers electrical dispersal fish barrier system.

DATES: Comments and related material must either be submitted to our online docket via *http://www.regulations.gov* on or before July 27, 2009 or reach the Docket Management Facility by that date.

ADDRESSES: You may submit comments identified by Coast Guard docket number USCG–2008–1247 using any 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.

To avoid duplication, please use only one of these methods. For instructions on submitting comments, see the ‘‘Public Participation and Request for Comments’’ portion of the **SUPPLEMENTARY INFORMATION** section below.

FOR FURTHER INFORMATION CONTACT: If you have questions on this proposed rule call LT Ann Henkelman, Waterways Management Branch, Ninth Coast Guard District, telephone 216–902–6288. 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:

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.

Submitting Comments

If you submit a comment, please include the docket number for this rulemaking (USCG–2008–1247), 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*, select the Advanced Docket Search option on the right side of the screen, insert ''USCG–2008–1247'' in the Docket ID box, press Enter, and 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 them by mail and would like to know that they reached the Facility, please enclose a stamped, self-addressed postcard or envelope. We will consider all comments and material received during the comment period and may change the rule based on your comments.

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,* select the Advanced Docket Search option on the right side of the screen, insert USCG–2008–1247 in the Docket ID box, press Enter, and then click on the item in the Docket ID column. You may also visit the Docket Management Facility in Room W12–140 on the ground floor of the Department of Transportation West Building, 1200 New Jersey Avenue, SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. We have an agreement with the Department of Transportation to use the Docket Management Facility.

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 notice regarding our public dockets in the January 17, 2008, issue of the **Federal Register** (73 FR 3316).

Public Meeting

We do not now 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.**

Background and Purpose

The Nonindigenous Aquatic Nuisance Prevention and Control Act of 1990, as amended by the National Invasive Species Act of 1996, authorized the Army Corps of Engineers (Army Corps) to conduct a demonstration project to identify an environmentally sound method for preventing and reducing the dispersal of non-indigenous aquatic nuisance species through the Chicago Sanitary and Ship Canal. The Army Corps selected an electric barrier because it is a non-toxic deterrent with a proven history and also does not overtly interfere with navigation in the canal.

In April 2002, the Army Corps energized a demonstration electrical dispersal barrier located in the Chicago Sanitary and Ship Canal approximately 30 miles from Lake Michigan. The demonstration barrier, commonly referred to as ''Barrier I,'' generates a low-voltage electric field (a maximum of approximately one-volt per inch) across the canal, which connects the Illinois River to Lake Michigan. The electric field is created by pulsing low voltage DC current through steel cables secured to the bottom of the canal. Barrier I was built to block the passage of aquatic nuisance species, such as Asian carp, and prevent them from moving between the Mississippi River basin and Great Lakes via the canal.

In the spring of 2004, a commercial towboat operator reported an electrical arc between a wire rope and timberhead while making up a tow in the vicinity of the Barrier I. During subsequent Army Corps safety testing in January 2005, sparking was observed upon metal-to-metal contact between two independent barges in the barrier field.

In 2006, the Army Corps completed construction of a second barrier, ''Barrier IIA.'' Barrier IIA was constructed 800 to 1300 feet downstream of the Barrier I. Barrier IIA is designed to operate continuously at one-volt per inch, and can operate at higher levels. Because of its design, Barrier IIA can generate a more powerful electric field, over a larger area within the Chicago Sanitary and Ship Canal, than Barrier I. The potential field strength for Barrier IIA will be up to four times that of the Barrier I. Barrier IIA was successfully operated for the first time, for approximately seven weeks in September and October 2008, while Barrier I was taken down for maintenance. Construction on a third barrier (Barrier IIB) is planned; Barrier IIB would augment the capabilities of Barriers I and IIA.

The electric current in the water poses a safety risk to commercial and recreational boaters transiting the area. The Navy Experimental Diving Unit (NEDU) was tasked with researching how the electric current from the barriers would affect a human body if immersed in the water. This comprehensive, independent analysis of Barriers I and IIA, conducted in 2008, at the one-volt per inch level, found a serious risk of injury or death to persons immersed in the water located adjacent to and over the barrier. The NEDU final report concluded that the possible effects to a human body if immersed in the water include paralysis of body muscles, inability to breathe, and ventricular fibrillation. Additionally, sparking between barges transiting the barrier (a risk to flammable cargoes) occurred at the one-volt per inch level. Operating Barrier IIA at four-volts per inch (the maximum capacity) presents a higher risk; however, there is no data yet to indicate how much higher.

A Safety Work Group facilitated by the Coast Guard and in partnership with the Army Corps and industry initially met in February 2008, and focused on three goals: (1) Education and public outreach, (2) keeping people out of the water, and (3) egress/rescue efforts. Eleven stakeholders have regularly attended the Safety Work Group. Key partners include the American Waterways Operators; Illinois River Carriers Association; Army Corps, Chicago District, Coast Guard Marine Safety Unit Chicago; Coast Guard Sector Lake Michigan; and the Ninth Coast Guard District. During the past 12 months, the Coast Guard has hosted 5 Safety Work Group meetings with full participation from stakeholders. The

Coast Guard and the Army Corps developed regulations and safety guidelines, with stakeholder input, which addressed the risks and hazards associated with operating the barriers at the one-volt per inch level. These regulations were published in 33 CFR 165.923, 70 FR 76692, Dec. 28, 2005, and in a series of temporary final rules: 71 FR 4488, Jan. 27, 2006; 71 FR 19648, Apr. 17, 2006; 73 FR 33337, Jun. 12, 2008; 73 FR 37810, Jul. 2, 2008; 73 FR 45875, Aug. 7, 2008; and 73 FR 63633, Oct. 27, 2008.

The Army Corps notified the Coast Guard in December 2008, that it planned to activate Barrier IIA on a full-time basis starting in middle to late January 2009. Due to technical issues, Barrier IIA was not activated until April 8, 2009. Both Barrier IIA and Barrier I are operating at the same time. Operation of both Barrier I and Barrier IIA at the same time provides a back up should one barrier cease to operate.

The Coast Guard advised the Army Corps in December 2008, that it had no objection to the Army Corps activating Barrier IIA at a maximum strength of one-volt per inch, which is the operating strength of Barrier I. In addition, the Coast Guard advised the Army Corps that it did not object to the Army Corps' plans for additional testing of Barrier IIA at peak field strength of up to four-volts per inch. Peak field strength tests are necessary to evaluate safety risks to mariners and their vessels when Barrier IIA is operated at a higher voltage.

Based on the commercial significance and successful transit history of the Barrier I by thousands of barges since its inception in April 2002, and Barrier IIA during Fall 2008, the Coast Guard has not chosen to close the waterway despite the proven electrical discharge hazard and additional safety concerns. Tows spanning Barrier IIA and the coal-fired power plant barge loading area just south of the regulated navigation area remain a concern. Accordingly, because of the safety risks involved, it is imperative that the Coast Guard implements increased safety measures for the operation of both Barriers I and IIA.

To mitigate the safety risks created by operation of both barriers, the Coast Guard established a temporary interim rule (TIR) on January 16, 2009, which placed navigational and operational restrictions on all vessels transiting through a regulated navigation area located adjacent to and over the barriers. 33 CFR 165.T09–1247, 74 FR 6357, Feb. 9, 2009. The TIR public comment period closed on April 10, 2009. To date, no comments have been received regarding the TIR.

This notice of proposed rulemaking (NPRM) proposes establishment of permanent regulations, similar to the regulations contained in the TIR. Like the TIR, this rule proposes placement of navigational and operational restrictions on all vessels transiting through a regulated navigation area located adjacent to and over the barriers. Specifically, the Coast Guard proposes requiring vessels transiting the regulated navigation area to adhere to specified operational and navigational requirements. In addition, the Coast Guard will occasionally enforce a safety zone, which prohibits the movement of all vessels and persons through the electrical dispersal barriers during tests or other periods of time that Barrier IIA is operated at voltages higher than one-volt per inch.

To view the TIR, this NPRM, as well as documents mentioned in this preamble as being available in the docket, go to *http://www.regulations.gov* at any time, click on ''Search for Dockets,'' and enter the docket number for this rulemaking (USCG–2008–1247) in the Docket ID box, and click enter. You may also visit the Docket Management Facility in Room W12–140 on the ground floor of the DOT West Building, 1200 New Jersey Avenue, SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Discussion of Proposed Rule

This rule proposes removal of 33 CFR 165.923 and 33 CFR 165.T09–1247. This rule proposes establishment of permanent regulations, which would place navigational and operational restrictions on all vessel transits through the navigable waters located adjacent to and over the electrical dispersal barriers located on the Chicago Sanitary and Ship Canal. The regulated navigation area encompasses all waters of the Chicago Sanitary and Ship Canal located between mile marker 295.0 (approximately 1.1 miles south of the Romeo Road Bridge) and mile marker 297.5 (approximately 1.3 miles northeast of the Romeo Road Bridge). The requirements placed on commercial vessels include: (1) Vessels engaged in commercial service, as defined in 46 U.S.C. 2101(5), may not pass (meet or overtake) in the regulated navigation area and must make a SECURITE call when approaching the regulated navigation area to announce intentions; (2) vessels engaged in commercial service must work out passing arrangements prior to entering the regulated navigation area and may only pass (meet or overtake) another vessel outside of the regulated navigation area; (3) commercial tows transiting the regulated navigation area must be made up with wire rope to ensure electrical connectivity between all segments of the tow; and (4) all up-bound and down-bound barge tows that contain one or more red flag barges must be assisted by a bow boat until the entire tow is clear of the regulated navigation area. The Army Corps has informed the Coast Guard that the Army Corps will continue to contract bow boat assistance for barge tows containing one or more red flag barges through the remainder of the current fiscal year (*i.e.,* through September 30, 2009). The Army Corps has informed the Coast Guard that it will request funds for bow boat assistance in its fiscal year 2010 budget request. However, because of the federal budget process, there is currently no way to determine if those funds will be appropriated. In the event Army Corps funding would cease, operators of tows containing one or more red flag barges that need to transit through the regulated navigation area would incur the cost of bow boat assistance. Operators of tows containing one or more red flag barges must notify the bow boat contractor at least two hours prior to the need for assistance. The tow operator must then remain in contact with the contractor after the initial call for bow boat assistance and advise the contractor of any delays.

Red flag barges are barges certificated to carry, in bulk, any hazardous material as defined in 46 CFR 150.115. Currently, 46 CFR 150.115 defines hazardous material as:

(a) A flammable liquid as defined in 46 CFR 30.10–22 or a combustible liquid as defined in 46 CFR 30.10–15;

(b) A material listed in Table 151.05, Table 1 of part 153, or Table 4 of part 154 of Title 46, CFR; or

(c) A liquid, liquefied gas, or compressed gas listed in 49 CFR 172.101.

This rule proposes additional restrictions and operating requirements on all vessels within a smaller portion of the regulated navigation area, specifically, the waters between the Romeo Road Bridge (approximate mile marker 296.18) and mile marker 296.7 (aerial pipeline located approximately 0.52 miles north east of Romeo Road Bridge). Within this smaller area, this rule proposes the prohibition of vessel loitering, mooring or laying up on the right or left descending banks, or making or breaking tows on the waters between the Romeo Road Bridge (approximate mile marker 296.18) and mile marker 296.7 (aerial pipeline located approximately 0.52 miles north east of Romeo Road Bridge). In addition, vessels may only enter the waters between the Romeo Road Bridge (approximate mile marker 296.18) and mile marker 296.7 (aerial pipeline located approximately 0.52 miles north east of Romeo Road Bridge) for the sole purpose of transiting to the other side and must maintain headway throughout the transit. All vessels and persons are prohibited from dredging, laying cable, dragging, fishing, conducting salvage operations, or any other activity, which could disturb the bottom of the canal in the area located between the Romeo Road Bridge (approximate mile marker 296.18) and mile marker 296.7 (aerial pipeline located approximately 0.52 miles north east of Romeo Road Bridge). The rule also proposes that all persons on open decks of a vessel engaged in commercial service must wear a Coast Guard approved Type I personal flotation device while on the waters between the Romeo Road Bridge (approximate mile marker 296.18) and mile marker 296.7 (aerial pipeline located approximately 0.52 miles north east of Romeo Road Bridge). All persons on recreational vessels that are propelled or controlled by machinery, sails, oars, paddles, poles or another vessel must wear the Coast Guard approved personal flotation device (PFD) that is required to be onboard by 33 CFR Part 175, while on the waters between the Romeo Road Bridge (approximate mile marker 296.18) and mile marker 296.7 (aerial pipeline located approximately 0.52 miles north east of Romeo Road Bridge).

These restrictions are necessary for safe navigation of the regulated navigation area and to ensure the safety of vessels and their personnel as well as the public's safety due to the electrical discharges noted during safety tests conducted by the Army Corps. Deviation from this rule would be prohibited unless specifically authorized by the Commander, Ninth Coast Guard District, or his designated representatives. The Commander, Ninth Coast Guard District, will designate Captain of the Port Lake Michigan and Commanding Officer, Marine Safety Unit Chicago, as his designated representatives for the purposes of the proposed regulated navigation area.

A safety zone would be enforced during tests or other periods of time that Barrier IIA is operated at voltages higher than one volt per inch. This proposed safety zone, which would encompass all the waters of the Chicago Sanitary and Ship Canal located between mile marker 296.0 (approximately 958 feet south of the Romeo Road Bridge) and mile marker 296.7 (aerial pipeline located approximately 0.52 miles north east of Romeo Road Bridge), would be enforced by the Captain of the Port Lake Michigan, for such times before, during, and after barrier testing as he or she deems necessary to protect mariners and vessels from damage or injury. The Captain of the Port Lake Michigan would cause notice of enforcement or suspension of enforcement of this safety zone to be made by all appropriate means to effect the widest publicity among the affected segments of the public. Such means of notification will include, but will not be limited to, Broadcast Notice to Mariners and Local Notice to Mariners. The Captain of the Port Lake Michigan would issue a Broadcast Notice to Mariners notifying the public when enforcement of the safety zone is suspended. In addition, Captain of the Port Lake Michigan maintains a telephone line that is manned 24 hours a day, seven days a week. The public may obtain information concerning enforcement of the safety zone by contacting the Captain of the Port Lake Michigan via the Coast Guard Sector Lake Michigan Command Center at 414–747–7182.

Regulatory Planning and Review

This proposed rule is not a ''significant regulatory action'' under section 3(f) of Executive Order 12866, Regulatory Planning and Review, and does not require an assessment of potential costs and benefits under section 6(a)(3) of that Order. The Office of Management and Budget has not reviewed it under that Order. Nevertheless, we have prepared a preliminary Regulatory Analysis of potential costs and benefits which is available in the docket where indicated under the **ADDRESSES** section of this preamble. A summary of the analysis follows:

This proposed rule would mitigate safety risks associated with the electrical fish barrier system in the Chicago Sanitary and Ship Canal near Romeoville, Illinois. The Army Corps operates and maintains the fish barrier. Navigational and operational restrictions are necessary for all vessels transiting through the navigable waters located adjacent to and over the barriers in order to mitigate safety risks.

The proposed rule would establish a permanent regulated navigation area for navigable waters adjacent to and over the electrical fish barrier. The rulemaking would also require certain provisions while transiting the regulated navigation area, including bow boat assistance for tows with red flag barges. Other proposed requirements of this rulemaking clarify navigation requirements that are normal industry practice (*e.g.,* commercial tows using wire ropes) or have been in existence since 2002 as a result of the Army Corps' development, operation, and maintenance of the electrical fish barrier. See the ''Background and Purpose'' and ''Discussion of Proposed rule'' sections for additional details on the requirements.

This proposed rule would affect traffic transiting over the electrical fish barrier and surrounding waters. The Army Corps maintains data about the commercial vessels using the Lockport Lock and Dam, which provides access to the proposed regulated navigation area. During 2007, the commercial traffic through the Lockport Lock consisted of 147 towing vessels and 13,411 barges. Of those, 100 towing vessels and 2,246 barges were handling red flag cargo. There were 983 lockages involving red flag barges in 2007.

The potential cost associated with this proposed rule would be for bow boat assistance. The Army Corps currently covers this cost through contract funding. In the event that such funding would cease, operators needing to transit the regulated navigation area with one or more red flag barges would incur a cost of approximately $850 per one-way transit (*i.e.,* based on current Army Corps funding estimates).

If bow boat assistance funding were to cease, we estimate the undiscounted annual recurring cost to industry to be $835,550 (*i.e.,* 983 potential red flag transits × $850 for bow boat assistance fee). Based on this potential annual cost, we estimate the total present value 10-year (2010–2019) cost to industry of this proposed rule to be approximately $5.9 million at a seven percent discount rate and $7.1 million at a three percent discount rate.

We expect this proposed rule would mitigate the marine safety risks as a result of the permanent operation and maintenance of the electrical fish barriers. This rulemaking would also allow commerce to continue through the waters adjacent to or over these barriers.

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.

An Initial Regulatory Flexibility Analysis (IRFA) discussing the impact of this proposed rule on small entities is available in the docket where indicated under the ''Public Participation and Request for Comments'' section of this preamble.

From our analysis, we found the proposed rule would affect an estimated 23 entities, of which 10 are considered small entities according to SBA size standards. If operators incur the direct cost of bow boat assistance, we estimate five (or fifty percent) of the affected small entities would incur a cost impact of less than or equal to one percent of revenue and eight (or eighty percent) of the affected small entities would incur a cost impact of less than or equal to three percent of revenue.

At this time, the Coast Guard certifies under 5 U.S.C. 605(b) that this proposed rule would not have a significant economic impact on a substantial number of small entities. If you think that your business, organization, or governmental jurisdiction qualifies as a small entity and that this rule would have a significant economic impact on it, please submit a comment to the docket as detailed under **ADDRESSES**. In your comment explain why, how, and to what degree you think this proposed rule would have an economic impact on you.

Assistance for Small Entities

Under section 213(a) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121), we want to assist small entities in understanding the rule so that they may better evaluate its effects on them and participate in the rulemaking. If the rule would affect your small business, organization, or governmental jurisdiction and you have questions concerning its provisions or options for compliance, please contact LT Ann Henkelman, Waterways Management Branch, Ninth Coast Guard District, 1240 East Ninth Street, Cleveland, OH 44199; 216–902–6288. The Coast Guard will not retaliate against small entities that question or complain about this rule or any policy or action of the Coast Guard.

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).

Federalism

A rule has implications for federalism under Executive Order 13132, Federalism, if it has 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 proposed rule under that Order and have determined that it does not have implications for federalism.

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.

Taking of Private Property

This rule will not effect a taking of private property or otherwise have taking implications under Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

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.

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 concern an environmental risk to health or risk to safety that may disproportionately affect children.

Indian Tribal Governments

The Coast Guard recognizes the treaty rights of Native American Tribes. Moreover, the Coast Guard is committed to working with Tribal Governments to implement local policies and to mitigate tribal concerns. We have determined that these regulations and fishing rights protection need not be incompatible. We have also determined that this proposed 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. Nevertheless, Indian Tribes that have questions concerning the provisions of this proposed rule or options for compliance are encouraged to contact the point of contact listed under **FOR FURTHER INFORMATION CONTACT**.

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.

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 procedure; and related management system practices) that are developed or adopted by voluntary consensus standards bodies.

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

Environment

We have analyzed this proposed rule under Department of Homeland Security Management Directive 023–01 and Commandant Instruction M16475.lD, which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321–4370f), and have made a preliminary determination that this action is one of a category of actions which do not individually or cumulatively have a significant effect on the human environment. Therefore, this rule is categorically excluded, under section 2.B.2. Figure 2–1, paragraph 34(g), of the Instruction and neither an environmental assessment nor an environmental impact statement is required. This rule involves the establishing, disestablishing, or changing regulated navigation areas and security or safety zones. A preliminary ''Environmental Analysis Check List'' supporting this determination is available in the docket where indicated under the ''Public Participation and Request for Comments'' section of this preamble. We seek any comments or information that may lead to discovery of a significant environmental impact from this proposed rule.

List of Subjects in 33 CFR Part 165

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

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

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

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

Authority: 33 U.S.C. 1226, 1231; 46 U.S.C. Chapter 3306, 3703 and Chapter 701; 50 U.S.C. 191, 195; 33 CFR 1.05–1, 6.04–1, 6.04–6, and 160.5; Pub. L. 107–295, 116 Stat. 2064; Department of Homeland Security Delegation No. 0170.1.

§ 165.923 [Removed]

2. Remove § 165.923.

3. Add § 165.924 to read as follows:

§ 165.924 Regulated Navigation Area and Safety Zone, Chicago Sanitary and Ship Canal, Romeoville, IL

(a) *Regulated Navigation Area.* The following is a Regulated Navigation Area: All waters of the Chicago Sanitary and Ship Canal, Romeoville, IL, located between mile marker 295.0 (approximately 1.1 miles south of the Romeo Road Bridge) and mile marker 297.5 (approximately 1.3 miles northeast of the Romeo Road Bridge).

(1) *Definitions.* The following definitions apply to this section:

Bow boat means a towing vessel capable of providing positive control of the bow of a tow containing one or more barges, while transiting the regulated navigation area. The bow boat must be capable of preventing a tow containing one or more barges from coming into contact with the shore and other moored vessels.

Designated representatives means the Captain of the Port Lake Michigan and Commanding Officer, Marine Safety Unit Chicago.

Hazardous material means any material as defined in 46 CFR 150.115.

On-scene representative means any Coast Guard commissioned, warrant or petty officer who has been designated by the Captain of the Port Lake Michigan to act on his behalf.

Red flag barge means any barge certificated to carry any hazardous material in bulk.

(2) *Regulations.* (i) The general regulations contained in 33 CFR 165.13 apply.

(ii) All up-bound and down-bound barge tows that contain one or more red flag barges transiting through the regulated navigation area must be assisted by a bow boat until the entire tow is clear of the regulated navigation area.

(iii) Vessels engaged in commercial service, as defined in 46 U.S.C 2101(5), may not pass (meet or overtake) in the regulated navigation area and must make a SECURITE call when approaching the regulated navigation area to announce intentions. Vessels engaged in commercial service must work out passing arrangements prior to entering the regulated navigation area and may only pass (meet or overtake) another vessel outside of the regulated navigation area.

(iv) Commercial tows transiting the regulated navigation area must be made up with wire rope to ensure electrical connectivity between all segments of the tow.

(v) All vessels are prohibited from loitering between the Romeo Road Bridge (approximate mile marker 296.18) and mile marker 296.7 (aerial pipeline located approximately 0.52 miles north east of Romeo Road Bridge).

(vi) Vessels may enter the waters between the Romeo Road Bridge (approximate mile marker 296.18) and mile marker 296.7 (aerial pipeline located approximately 0.52 miles north east of Romeo Road Bridge) for the sole purpose of transiting to the other side and must maintain headway throughout the transit. All vessels and persons are prohibited from dredging, laying cable, dragging, fishing, conducting salvage operations, or any other activity, which could disturb the bottom of the canal in the area located between the Romeo Road Bridge (approximate mile marker 296.18) and mile marker 296.7 (aerial pipeline located approximately 0.52 miles north east of Romeo Road Bridge).

(vii) All persons on open decks of a vessel engaged in commercial service must wear a Coast Guard approved Type I personal flotation device (PFD) while in the waters between the Romeo Road Bridge (approximate mile marker 296.18) and mile marker 296.7 (aerial pipeline located approximately 0.52 miles north east of Romeo Road Bridge). All persons on recreational vessels that are propelled or controlled by machinery, sails, oars, paddles, poles or another vessel must wear the Coast Guard approved PFD that is required to be onboard by 33 CFR Part 175, while on the waters between the Romeo Road Bridge (approximate mile marker 296.18) and mile marker 296.7 (aerial pipeline located approximately 0.52 miles north east of Romeo Road Bridge).

(viii) Vessels may not moor or lay up on the right or left descending banks of the waters between the Romeo Road Bridge (approximate mile marker 296.18) and mile marker 296.7 (aerial pipeline located approximately 0.52 miles north east of Romeo Road Bridge).

(ix) Towboats may not make or break tows if any portion of the towboat or tow is located in the waters between the Romeo Road Bridge (approximate mile marker 296.18) and mile marker 296.7 (aerial pipeline located approximately 0.52 miles north east of Romeo Road Bridge).

(3) *Compliance.* All persons and vessels must comply with this section and any additional instructions or orders of the Ninth Coast Guard District Commander, or his designated representatives.

(4) *Waiver.* For any vessel, the Ninth Coast Guard District Commander, or his designated representatives, may waive any of the requirements of this section, upon finding that operational conditions or other circumstances are such that application of this section is unnecessary or impractical for the purposes of vessel and mariner safety.

(b) *Safety Zone.* (1) The following area is a safety zone: All waters of the Chicago Sanitary and Ship Canal located between mile marker 296.0 (approximately 958 feet south of the Romeo Road Bridge) and mile marker 296.7 (aerial pipeline located approximately 0.52 miles north east of Romeo Road Bridge).

(2) *Notice of enforcement or suspension of enforcement.* The Captain of the Port Lake Michigan will enforce the safety zone established by this section only upon notice. Captain of the Port Lake Michigan will cause notice of the enforcement of this safety zone to be made by all appropriate means to effect the widest publicity among the affected segments of the public including publication in the **Federal Register** as practicable, in accordance with 33 CFR 165.7(a). Such means of notification may also include, but are not limited to, Broadcast Notice to Mariners or Local Notice to Mariners. The Captain of the Port Lake Michigan will issue a Broadcast Notice to Mariners and Local Notice to Mariners notifying the public when enforcement of these safety zones is suspended.

(3) *Regulations.* (i) In accordance with the general regulations in § 165.23 of this part, entry into, transiting, or anchoring within this safety zone is prohibited unless authorized by the Captain of the Port Lake Michigan, or his on-scene representative.

(ii) This safety zone is closed to all vessel traffic, except as may be permitted by the Captain of the Port Lake Michigan or his on-scene representative.

(iii) The on-scene representative of the Captain of the Port Lake Michigan may be aboard either a Coast Guard or Coast Guard Auxiliary vessel. The Captain of the Port Lake Michigan or his on-scene representative may be contacted via VHF Channel 16.

(4) Vessel operators desiring to enter or operate within the safety zone shall contact the Captain of the Port Lake Michigan or his on-scene representative to obtain permission to do so. Vessel operators given permission to enter or operate in the safety zone must comply with all directions given to them by the Captain of the Port Lake Michigan or his on-scene representative.

Dated: May 12, 2009.

D.R. Callahan,

Captain, U.S. Coast Guard, Commander, Ninth Coast Guard District Acting.

[FR Doc. E9–12179 Filed 5–22–09; 8:45 am]

BILLING CODE 4910–15–P

DEPARTMENT OF EDUCATION

34 CFR Chapter VI

Negotiated Rulemaking Committees; Establishment

AGENCY: Office of Postsecondary Education, Department of Education.

ACTION: Establishment of negotiated rulemaking committees; and notice of public hearings.

SUMMARY: We announce our intention to establish one or more negotiated rulemaking committees to prepare proposed regulations under Title IV of the Higher Education Act of 1965, as amended (HEA). The committees will include representatives of organizations or groups with interests that are significantly affected by the subject matter of the proposed regulations. We also announce three public hearings, at which interested parties may suggest additional issues that should be considered for action by the negotiating committees. In addition, for anyone unable to attend a public hearing, we announce that the Department will accept written comments.

The Department will also be conducting forums after each of the three hearings to discuss (1) how changes in the Department's financial aid communications and processes (including the Free Application for Federal Student Aid (FAFSA)) could improve college planning, preparation and access, and (2) how best to leverage Federal postsecondary programs to foster student educational persistence and degree attainment.

DATES: The dates, times, and locations of the public hearings are listed under the **SUPPLEMENTARY INFORMATION** section of this notice. We must receive written comments suggesting issues that should be considered for action by the negotiating committees on or before June 23, 2009.

ADDRESSES: Please send written comments to Wendy Macias, U.S. Department of Education, 1990 K Street, NW., Room 8017, Washington, DC 20006, or by fax to Wendy Macias at (202) 502–7874. You may also e-mail your comments to *negreg09@ed.gov.*

FOR FURTHER INFORMATION CONTACT: For information about the public hearings and forums, go to *http://www.ed.gov/policy/highered/reg/hearulemaking/2009/negreg-summerfall.html* or contact: Mary Miller, U.S. Department of Education, 1990 K Street, NW., Room 8066, Washington, DC 20006. Telephone: (202) 502–7824. You may also e-mail your questions about the public hearings to: *Mary.Miller@ed.gov.*

For information about negotiated rulemaking in general, see *The Negotiated Rulemaking Process for Title IV Regulations, Frequently Asked Questions* at *http://www.ed.gov/policy/highered/reg/hearulemaking/hea08/neg-reg-faq.html.* For further information about negotiated rulemaking contact: Wendy Macias, U.S. Department of Education, 1990 K Street, NW., Room 8017, Washington, DC 20006. Telephone (202) 502–7526. You may also e-mail your questions about negotiated rulemaking to: *Wendy.Macias@ed.gov.*

If you use a telecommunications device for the deaf (TDD), call the Federal Relay Service (FRS), toll free, at 1–800–877–8339.

Individuals with disabilities can obtain this document in an accessible format (e.g., braille, large print, audiotape, or computer diskette) by contacting the person responsible for information about the public hearings.

SUPPLEMENTARY INFORMATION: Section 492 of the HEA requires that, before publishing any proposed regulations to implement programs authorized under Title IV of the HEA, the Secretary obtain public involvement in the development of the proposed regulations. After obtaining advice and recommendations from the public, the Secretary uses a negotiated rulemaking process to develop the proposed regulations.

We announce our intent to develop proposed regulations by following the negotiated rulemaking procedures in section 492 of the HEA. We intend to select participants for the negotiated rulemaking committees from nominees of the organizations and groups that represent the interests significantly affected by the proposed regulations. To the extent possible, we will select, from the nominees, individual negotiators who reflect the diversity among program participants, in accordance with section 492(b)(1) of the HEA.

Regulatory Issues

We intend to convene one committee to develop proposed regulations governing foreign schools, including the implementation of the changes made to the HEA by the Higher Education Opportunity Act (HEOA), Public Law 110–315, that affect foreign schools.

We intend to convene at least one other committee to develop proposed regulations to maintain or improve program integrity in the Title IV, HEA programs, relating to topics such as the following:

- Satisfactory academic progress.
- Incentive compensation paid by institutions to persons or entities engaged in student recruiting or admission activities.
- Gainful employment in a recognized occupation.
- State authorization as a component of institutional eligibility.
- Definition of a credit hour, for purposes of determining program eligibility status, particularly in the context of awarding Pell Grants.
- Verification of information included on student aid applications.
- Definition of a high school diploma as a condition of receiving Federal student aid.

After a complete review of the public comments presented at the public hearings and from the written submissions, we will publish a subsequent notice (or notices) announcing the specific subject areas for which we intend to establish negotiated rulemaking committees, and a request for nominations for individual negotiators for those committees who represent the interests significantly affected by the proposed regulations.

Public Hearings

We will hold three public hearings for interested parties to discuss the agenda for the negotiated rulemaking sessions. The public hearings will be held on:

- June 15–16, 2009 at the Community College of Denver.
- June 18–19, 2009 at the University of Arkansas at Little Rock.
- June 22–23, 2009 at the Community College of Philadelphia.

The public hearings will be held from 9 a.m.–4 p.m., local time. Further information on the public hearing sites, including addresses and directions, is available at *http://www.ed.gov/policy/highered/reg/hearulemaking/2009/negreg-summerfall.html.*

On the day following each public hearing, the Department will also be conducting two forums at the same location as the public hearing, from 9 a.m.–1 p.m., local time. These forums will be conducted concurrently. One forum will focus on approaches to the Department's financial aid communications and processes (including the FAFSA) that could improve college planning, preparation and access. The other forum will focus on ways that Federal postsecondary programs could play a stronger role in fostering student educational persistence and degree attainment. While the Department will be inviting representatives of students, families, college access professionals, and college success practitioners to participate in these forums, the forums will be open to the public with opportunities for public comment provided.

Individuals desiring to present comments at the public hearings are encouraged to do so. It is likely that each participant choosing to make a statement will be limited to five minutes. Individuals interested in making oral statements will be able to register to make a statement beginning at 8:30 a.m. on the day of the public hearing at the Department's on-site registration table on a first-come, first-served basis. If additional time slots remain, individuals may be given additional time to speak. If no time slots remain, the Department has reserved one additional hour at the end of the day for individuals who were not able to register to speak. The amount of time available will depend upon the number of individuals who register to speak. Speakers may also submit written comments. In addition, for anyone unable to attend a public hearing, the Department will accept written comments through June 23, 2009. (See the **ADDRESSES** section of this notice for submission information.)

The public hearing sites are accessible to individuals with disabilities. Individuals needing an auxiliary aid or service to participate in the hearing or a forum (e.g., interpreting service, assistive listening device, or materials in alternative format) should notify the contact person for information about hearings listed under **FOR FURTHER INFORMATION CONTACT** in this notice in advance of the scheduled hearing date. Although we will attempt to meet any request we receive, we may not be able to make available the requested auxiliary aid or service because of insufficient time to arrange it.

Schedule for Negotiations

We anticipate that these committees will begin negotiations in September 2009, with each committee meeting for three sessions of approximately three days at roughly monthly intervals. The committees will meet in the Washington, DC area. The dates and locations of these meetings will be published in a subsequent notice in the **Federal Register,** and will be posted on the Department's Web site at: *http://www.ed.gov/policy/highered/reg/hearulemaking/2009/negreg-summerfall.html.*

Electronic Access to This Document

You may view this document, in text or Adobe Portable Document Format (PDF), on the Internet at the following site: *http://www.ed.gov/news/fedregister.* To use PDF you must have Adobe Acrobat Reader, which is available free at this site. If you have questions about using PDF, call the U.S. Government Printing Office toll free at 1–888–293–6498; or in the Washington, DC area at (202) 512–1530.

Note: The official version of this document is the document published in the **Federal Register**. Free Internet access to the official edition of the **Federal Register** and the Code of Federal Regulations is available on GPO Access at: *http://www.gpoaccess.gov/nara/index.html.*

Program Authority: 20 U.S.C. 1098a.

Delegation of Authority: The Secretary of Education has delegated authority to Daniel T. Madzelan, Director, Forecasting and Policy Analysis for the Office of Postsecondary Education, to perform the functions of the Assistant Secretary for Postsecondary Education.

Dated: May 20, 2009.

Daniel T. Madzelan,

Director, Forecasting and Policy Analysis.

[FR Doc. E9–12092 Filed 5–22–09; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

44 CFR Part 67

[Docket ID FEMA–2008–0020; Internal Agency Docket No. FEMA–B–1053]

Proposed Flood Elevation Determinations

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Proposed rule.

SUMMARY: Comments are requested on the proposed Base (1% annual-chance) Flood Elevations (BFEs) and proposed BFE modifications for the communities listed in the table below. The purpose of this notice is to seek general information and comment regarding the proposed regulatory flood elevations for the reach described by the downstream and upstream locations in the table below. The BFEs and modified BFEs are a part of the floodplain management measures that the community is required either to adopt or show evidence of having in effect in order to qualify or remain qualified for participation in the National Flood Insurance Program (NFIP). In addition, these elevations, once finalized, will be used by insurance agents, and others to calculate appropriate flood insurance premium rates for new buildings and the contents in those buildings.

DATES: Comments are to be submitted on or before August 24, 2009.

ADDRESSES: The corresponding preliminary Flood Insurance Rate Map (FIRM) for the proposed BFEs for each community are available for inspection at the community's map repository. The respective addresses are listed in the table below.

You may submit comments, identified by Docket No. FEMA–B–1053, to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–3151, or (e-mail) *bill.blanton@dhs.gov.*

FOR FURTHER INFORMATION CONTACT: William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–3151 or (e-mail) *bill.blanton@dhs.gov.*

SUPPLEMENTARY INFORMATION: The Federal Emergency Management Agency

(FEMA) proposes to make determinations of BFEs and modified BFEs for each community listed below, in accordance with section 110 of the Flood Disaster Protection Act of 1973, 42 U.S.C. 4104, and 44 CFR 67.4(a).

These proposed BFEs and modified BFEs, together with the floodplain management criteria required by 44 CFR 60.3, are the minimum that are required. They should not be construed to mean that the community must change any existing ordinances that are more stringent in their floodplain management requirements. The community may at any time enact stricter requirements of its own, or pursuant to policies established by other Federal, State, or regional entities. These proposed elevations are used to meet the floodplain management requirements of the NFIP and are also used to calculate the appropriate flood insurance premium rates for new buildings built after these elevations are made final, and for the contents in these buildings.

Comments on any aspect of the Flood Insurance Study and FIRM, other than the proposed BFEs, will be considered. A letter acknowledging receipt of any comments will not be sent.

Administrative Procedure Act Statement. This matter is not a rulemaking governed by the Administrative Procedure Act (APA), 5 U.S.C. 553. FEMA publishes flood elevation determinations for notice and comment; however, they are governed by the Flood Disaster Protection Act of 1973, 42 U.S.C. 4105, and the National Flood Insurance Act of 1968, 42 U.S.C. 4001 *et seq.*, and do not fall under the APA.

National Environmental Policy Act. This proposed rule is categorically excluded from the requirements of 44 CFR part 10, Environmental Consideration. An environmental impact assessment has not been prepared.

Regulatory Flexibility Act. As flood elevation determinations are not within the scope of the Regulatory Flexibility Act, 5 U.S.C. 601–612, a regulatory flexibility analysis is not required.

Executive Order 12866, Regulatory Planning and Review. This proposed rule is not a significant regulatory action under the criteria of section 3(f) of Executive Order 12866, as amended.

Executive Order 13132, Federalism. This proposed rule involves no policies that have federalism implications under Executive Order 13132.

Executive Order 12988, Civil Justice Reform. This proposed rule meets the applicable standards of Executive Order 12988.

List of Subjects in 44 CFR Part 67

Administrative practice and procedure, Flood insurance, Reporting and recordkeeping requirements.

Accordingly, 44 CFR part 67 is proposed to be amended as follows:

PART 67—[AMENDED]

1. The authority citation for part 67 continues to read as follows:

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

§ 67.4 [Amended]

2. The tables published under the authority of § 67.4 are proposed to be amended as follows:

Flooding source(s)	Location of referenced elevation **	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL)		Communities affected
		Effective	Modified	
Coffee County, Alabama, and Incorporated Areas				
Beaverdam Creek	Approximately 3,492 feet upstream of confluence of Pea River and Beaverdam Creek.	+195	+199	City of Elba.
	Approximately 6,718 feet upstream of confluence of Pea River and Beaverdam Creek.	+203	+204	
Pea River	Approximately 3,160 feet downstream of the intersection of County Road 404 and Reese Avenue.	+191	+192	City of Elba, Unincorporated Areas of Coffee County.
	Approximately 13,918 feet upstream of confluence of Pea River and Whitewater Creek.	+205	+206	
Whitewater Creek	Approximately 2,000 feet upstream of State Route 203.	+198	+205	City of Elba, Unincorporated Areas of Coffee County.
	Approximately 14,458 feet upstream of State Route 203.	+205	+206	
Wilkerson Creek	From the Coffee County boundary with Geneva County.	None	+135	Unincorporated Areas of Coffee County.
	Approximately 2,140 feet upstream of the Coffee County boundary.	None	+138	
Wilson Mill Creek	Approximately 390 feet downstream of County Road 45.	None	+135	Unincorporated Areas of Coffee County.
	Just downstream of County Road 45	None	+137	

* National Geodetic Vertical Datum.
\+ North American Vertical Datum.
\# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.
** BFEs to be changed include the listed downstream and upstream BFEs, and include BFEs located on the stream reach between the referenced locations above. Please refer to the revised Flood Insurance Rate Map located at the community map repository (see below) for exact locations of all BFEs to be changed.

Flooding source(s)	Location of referenced elevation **	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) Effective	Modified	Communities affected

Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

City of Elba

Maps are available for inspection at 200 Buford Street, Elba, AL 36323.

Unincorporated Areas of Coffee County

Maps are available for inspection at 1065 East McKinnon Street, New Brockton, AL 36351.

Coconino County, Arizona, and Incorporated Areas

Flooding source(s)	Location of referenced elevation **	Effective	Modified	Communities affected
Bow and Arrow Wash	Approximately 50 feet downstream of South Lone Tree Road.	+6879	+6878	City of Flagstaff.
	Approximately 1,800 feet upstream of Lake Mary Road.	None	+6949	
Peak View Wash	At confluence with Rio de Flag	+7111	+7113	City of Flagstaff.
	Approximately 125 feet upstream of Lois Lane	+7121	+7123	
Rio de Flag	At Rio Rancho Road	+6519	+6521	City of Flagstaff, Unincorporated Areas of Coconino County.
	Approximately 150 feet downstream of Route 66	None	+6758	
	At Narrows Dam	+7086	+7087	
	Approximately 565 feet downstream of Hidden Hollow Road.	+7147	+7148	
Schultz Creek	Approximately 175 feet upstream of North Fort Valley Road.	None	+7006	City of Flagstaff, Unincorporated Areas of Coconino County.
	Approximately 0.57 mile upstream of Mary Russel Way.	None	+7140	
Schultz Creek Ponding	Approximately 50 feet upstream of the confluence with Rio de Flag.	None	#1	City of Flagstaff, Unincorporated Areas of Coconino County.
	Approximately 175 feet upstream of North Fort Valley Road.	None	#1	
Switzer Canyon Wash	Approximately 50 feet upstream of the upstream end of the East Route 66 culvert.	+6866	+6869	City of Flagstaff, Unincorporated Areas of Coconino County.
	Approximately 0.42 mile upstream of Elk Drive	+7029	+7030	

* National Geodetic Vertical Datum.
+ North American Vertical Datum.
# Depth in feet above ground.
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Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

City of Flagstaff

Maps are available for inspection at Flagstaff City Hall, 211 West Aspen Avenue, Flagstaff, AZ.

Unincorporated Areas of Coconino County

Maps are available for inspection at the Coconino County Department of Community Development, 2500 North Fort Valley Road, Building 1, Flagstaff, AZ.

Pulaski County, Arkansas, and Incorporated Areas

Flooding source(s)	Location of referenced elevation **	Effective	Modified	Communities affected
Bayou Meto	Approximately 3.48 miles downstream of Southeastern Avenue.	+244	+243	City of Jacksonville, Unincorporated Areas of Pulaski County.
	Approximately 3.87 miles downstream of Old Tom Box Road.	+266	+263	
	Just upstream of Davis Ranch Road	None	+320	
Bridge Drive	At the confluence of Bayou Meto	None	+266	Unincorporated Areas of Pulaski County.
	Approximately 1.35 miles upstream of Bridge Field Drive.	None	+271	

Flooding source(s)	Location of referenced elevation **	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) Effective	Modified	Communities affected
Five Mile Creek	At the confluence with Bayou Meto	+247	+248	Unincorporated Areas of Pulaski County.
	Just upstream of Rixie Road	+251	+252	
Jacks Bayou	Approximately 1.93 miles downstream of Preters Road.	None	+277	Unincorporated Areas of Pulaski County.
	Approximately 1,200 feet upstream of Peters Road	None	+283	
Jacks Bayou Tributary 10	Approximately 1,000 feet downstream of Mercury Drive.	None	+274	Unincorporated Areas of Pulaski County.
	Approximately 1,800 feet upstream of Hercules Drive	None	+279	

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\+ North American Vertical Datum.
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ADDRESSES

City of Jacksonville
Maps are available for inspection at One Industrial Drive, Jacksonville, AR 72076.

Unincorporated Areas of Pulaski County
Maps are available for inspection at 501 West Markham Street, Suite A, Little Rock, AR 72201.

Siskiyou County, California, and Incorporated Areas

Flooding source(s)	Location of referenced elevation **	Effective	Modified	Communities affected
Oregon Slough	Corporate Limits of the City of Montague and Siskiyou Unincorporated.	None	+2503	Unincorporated Areas of Siskiyou County.
	Approximately 0.4 mile downstream of Ager Road	None	+2515	
	Approximately 325 feet downstream of Ager Road	None	+2523	

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Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

Unincorporated Areas of Siskiyou County
Maps are available for inspection at the Siskiyou County Public Health and Community Development Department, 806 South Main Street, Yreka, CA.

Cass County, Illinois, and Incorporated Areas

Flooding source(s)	Location of referenced elevation **	Effective	Modified	Communities affected
Illinois River	The confluence with Camp Creek (Brown County), approximately 2,185 feet upstream of the Cass/Morgan boundary.	+447	+448	City of Beardstown, Unincorporated Areas of Cass County.
	The downstream end of Elm Island (Schuyler County), approximately 650 feet upstream of the Cass/Mason boundary.	+450	+452	
Illinois River Backwater on the Sangamon River.	The confluence with the Illinois River	+449	+451	Unincorporated Areas of Cass County.
	Approximately 12 miles upstream of the confluence with the Illinois River.	None	+452	
Panther Creek	Approximately 3,220 feet downstream of State Highway 78.	None	+458	Unincorporated Areas of Cass County.
	The Limit of Detailed Study, approximately 3,660 feet upstream of Main Street.	None	+472	
Sangamon River	Approximately 285 feet upstream of Old River Road	None	+456	Unincorporated Areas of Cass County, City of Beardstown.

Flooding source(s)	Location of referenced elevation **	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) Effective	Modified	Communities affected
	Approximately 1,600 feet upstream of State Highway 78.	None	+461	

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Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

City of Beardstown
Maps are available for inspection at Beardstown City Hall, 105 West 3rd Street, Beardstown, IL 62618.

Unincorporated Areas of Cass County
Maps are available for inspection at the Cass County Courthouse, 100 East Springfield Street, Virginia, IL 62691.

Jo Daviess County, Illinois, and Incorporated Areas

Apple River	Approximately 2.2 miles upstream of Crazy Hollow Road.	None	+616	Village of Hanover, Unincorporated Areas of Jo Daviess County.
	Approximately 0.78 miles upstream of North Washington Street.	None	+622	
Mississippi River	Approximately 559.7 miles upstream of the confluence with the Ohio River (approximately 0.6 miles upstream of West Diggen Hill Road extended).	+603	+604	Unincorporated Areas of Jo Daviess County.
	Approximately 572.3 miles upstream of the confluence with the Ohio River (approximately 1.5 miles upstream of Sand Ridge Road extended).	+607	+608	
Mississippi River Backwater	The Apple River from the Jo Daviess/Carroll County boundary (approximately 0.7 miles upstream of Savanna Army Depot Road in Carroll County).	None	+599	Unincorporated Areas of Jo Daviess County.
	Approximately 1.45 miles upstream of the Jo Daviess/ Carroll County boundary (approximately 200 feet upstream of West Whitton Road).	None	+599	
	The Galena River from the confluence with the Mississippi River (approximately 0.1 mile downstream of Railroad Bridge).	+604	+605	
	Approximately 0.86 miles upstream of the confluence with the Mississippi River (approximately 0.76 miles upstream of Railroad Bridge).	+604	+605	

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Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

Unincorporated Areas of Jo Daviess County
Maps are available for inspection at the Jo Daviess County Courthouse, 330 North Bench Street, Galena, IL 61036.

Village of Hanover
Maps are available for inspection at the Hanover Village Hall, 207 Jefferson Street, Hanover, IL 61041.

Schuyler County, Illinois, and Incorporated Areas

Illinois River	Approximately 0.4 miles downstream of the confluence with the La Moine River.	+448	+450	Unincorporated Areas of Schuyler County, Village of Browning.

Flooding source(s)	Location of referenced elevation **	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL)		Communities affected
		Effective	Modified	
	Approximately 2.55 miles upstream of the confluence with Elm Creek.	+451	+452	

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ADDRESSES

Unincorporated Areas of Schuyler County

Maps are available for inspection at the Schuyler County Highway Department, 121 Henninger Drive, Rushville, IL 62681.

Village of Browning

Maps are available for inspection at the Village Hall 501 Main Street, P.O. 169, Browning, IL 62624.

Worcester County, Massachusetts, and Incorporated Areas

Flooding source(s)	Location of referenced elevation **	Effective	Modified	Communities affected
Big Bummet River	Just downstream of State Highway 140	+384	+385	Town of Shrewsbury.
	At the corporate limits of the Town of Shrewsbury with the Town of Grafton.	+383	+385	
Blackstone River	Approximately 1,750 feet downstream of Saint Paul Street Bridge.	+160	+159	Town of Blackstone, City of Worcester, Town of Grafton, Town of Millbury, Town of Millville, Town of Northbridge, Town of Sutton, Town of Uxbridge.
	Approximately 250 feet downstream of Millbury Street Bridge.	+443	+444	
Cold Spring Brook	At its confluence with Blackstone River	+326	+323	Town of Sutton.
	Approximately 150 feet downstream of State Highway 122A.	+326	+325	
Cronin Brook	At its confluence with Blackstone River	+301	+298	Town of Grafton.
	Approximately 1,100 feet downstream of Follette Street.	+301	+302	
Goodridge Brook	Approximately 150 feet upstream of State Highway 70	None	+258	Town of Clinton.
	Approximately 250 feet downstream of Parker Road	None	+258	
Middle River	Approximately 250 feet downstream of Millbury Street Bridge.	+443	+444	City of Worcester.
	Approximately 100 feet downstream of McKeon Road	+451	+452	
Mill River	Approximately 3,900 feet downstream of Colonial Drive.	None	+196	Town of Blackstone.
	Approximately 1,300 feet downstream of Colonial Drive.	None	+198	
Mumford River	At its confluence with Blackstone River	+227	+225	Town of Uxbridge.
	Approximately 300 feet downstream of Mendon Street	+227	+226	
Quinsigamond River	At its confluence with Blackstone River	+295	+293	Town of Grafton.
	At Pleasant Street Bridge	+295	+293	
Riverdale Milles Sluice Gates and Tail Race.	Approximately 600 feet upstream of the confluence with Blackstone River.	+255	+256	Town of Northbridge.
	Approximately 100 feet upstream of Riverdale Street	+258	+259	
Singletary Brook	At its confluence with Blackstone River	+395	+393	Town of Millbury.
	Approximately 300 feet downstream of Rhodes Street	+395	+394	
West River	At its confluence with Blackstone River	+226	+224	Town of Uxbridge.
	Approximately 200 feet upstream of Henry Street Bridge.	+226	+225	

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Flooding source(s)	Location of referenced elevation **	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) Effective	Modified	Communities affected

** BFEs to be changed include the listed downstream and upstream BFEs, and include BFEs located on the stream reach between the referenced locations above. Please refer to the revised Flood Insurance Rate Map located at the community map repository (see below) for exact locations of all BFEs to be changed.

Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

City of Worcester
Maps are available for inspection at City Hall, 455 Main Street, Worcester, MA 01608.

Town of Blackstone
Maps are available for inspection at the Town Hall, 15 Saint Paul Street, Blackstone, MA 01504.

Town of Clinton
Maps are available for inspection at the Town Hall, 242 Church Street, Clinton, MA 01510.

Town of Grafton
Maps are available for inspection at the Town Hall, 30 Providence Road, Grafton, MA 01519.

Town of Millbury
Maps are available for inspection at the Town Hall, 127 Elm Street, Millbury, MA 01527.

Town of Millville
Maps are available for inspection at the Town Hall, 8 Central Street, Millville, MA 01529.

Town of Northbridge
Maps are available for inspection at the Town Hall, 7 Main Street, Whitinsville, MA 01588.

Town of Shrewsbury
Maps are available for inspection at the Town Hall, 100 Maple Avenue, Shrewsbury, MA 01545.

Town of Sutton
Maps are available for inspection at the Town Hall, 4 Uxbridge Road, Sutton, MA 01590.

Town of Uxbridge
Maps are available for inspection at the Town Hall, 21 South Main Street, Uxbridge, MA 01569.

Clinton County, Michigan, and Incorporated Areas

Looking Glass River	Just upstream of South Chandler Road	None	+805	Township of Victor, Township of Bath.
	Approximately 9,000 feet upstream of Babcock Road	None	+807	
Prairie Creek and Gunderman Lake Drain.	At confluence with Remey Chandler Drain	None	+817	Township of DeWitt.
	Approximately 7,410 feet upstream of West Stoll Road.	None	+832	
Remey Chandler Drain	Approximately 350 feet downstream of Interstate Highway 69.	None	+835	City of East Lansing, Township of Bath, Township of De Witt.
	Approximately 1,140 feet upstream of Coleman Road	None	+844	
Steel and Walbridge Drain	At confluence with Spaulding Drain	None	+730	City of St. Johns, Bingham.
	Approximately 600 feet upstream of Glastonbury Drive.	None	+752	

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ADDRESSES

Bingham
Maps are available for inspection at 1637 South DeWitt Road, St. Johns, MI 48879.

City of East Lansing
Maps are available for inspection at 410 Abbott Road, East Lansing, MI 48823–3388.

City of St. Johns
Maps are available for inspection at 100 East State Street, Suite 1100, St. Johns, MI 48879–0477.

Township of Bath
Maps are available for inspection at 14480 Webster Road, P.O. Box 247, Bath, MI 48808–0247.

Township of DeWitt

Flooding source(s)	Location of referenced elevation **	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) Effective	Modified	Communities affected

Maps are available for inspection at 1401 West Herbison Road, DeWitt, MI 48820.

Township of Victor

Maps are available for inspection at 6843 East Alward Road, Laingsburg, MI 48848–9256.

Ransom County, North Dakota, and Incorporated Areas

Sheyenne River	Approximately 1,064 feet upstream of Richland County Line.	None	+990	Unincorporated Areas of Ransom County.
	Approximately 7,465 feet downstream of State Highway 46.	None	+1160	

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ADDRESSES

City of Fort Ransom

Maps are available for inspection at P.O. Box 17, Fort Ransom, ND 58033.

City of Lisbon

Maps are available for inspection at P.O. Box 1079, Lisbon, ND 58054.

Unincorporated Areas of Ransom County

Maps are available for inspection at 204 5th Avenue West, Lisbon, ND 58054–4115.

Cuyahoga County, Ohio, and Incorporated Areas

Anthony Lake Tributary	Approximately 425 feet downstream of Anthony Lane	+895	+897	City of Parma Heights, City of Parma.
	Approximately 140 feet upstream of Anthony Lane	+895	+902	
Big Creek	Approximately 300 feet downstream of Ridge Road	None	+679	City of Brooklyn.
	Approximately 1,100 feet upstream of Ridge Road	None	+695	
Chagrin River	Approximately ½ mile upstream of Rogers Road	None	+683	Village of Mayfield.
Chagrin River	Approximately 40 feet upstream of Woodland Road	None	+786	Village of Moreland Hills.
	Approximately 1,200 feet upstream of Woodland Road.	None	+789	
	Approximately 850 feet downstream of Miles Road	None	+851	
	Approximately 1,200 feet upstream of Miles Road	None	+860	
Countrymans Creek	Upstream of Interstate 71	None	+721	Village of Linndale.
	Downstream of Bellaire Road	None	+727	
Cuyahoga River	Approximately 40 feet upstream of Brecksville Road	None	+605	City of Garfield Heights.
	Approximately 700 feet upstream of Brecksville Road	None	+607	
Doan Brook	Approximately 160 feet upstream of Martin Luther King Jr. Drive.	None	+777	City of Cleveland Heights.
	Approximately 130 feet upstream of West Woodland Road.	None	+915	
Dover Ditch	Approximately 150 feet downstream of Harding Drive	None	+724	City of North Olmsted.
Gifford-Avon Ditch	Approximately 100 Feet upstream of Naigle Road	+622	+629	City of Westlake.
	Approximately 0.5 mile upstream of Naigle Road	+626	+629	
Lake Erie	Entire Shoreline	+589	+576	City of Bay Village, City of Cleveland, City of Lakewood.
Mill Creek	Approximately 30 feet downstream of McCracken Road.	+839	+841	City of Maple Heights.
	Approximately 390 feet upstream of McCracken Road	+840	+841	
Plum Creek	Mouth at West Branch Rocky River	None	+710	City of Olmsted Falls.
	Approximately 70 feet downstream of Sprague Road	None	+780	
Plum Creek	Approximately 2,900 feet upstream of Bagley Road	+758	+764	Unincorporated Areas of Cuyahoga County.
	Approximately 70 feet downstream of Sprague Road	+777	+780	
Rocky River	Approximately 775 feet downstream of River Road	None	+600	City of Cleveland.
	Approximately 3,500 feet upstream of River Road	None	+606	
Rocky River	Approximately 1,100 feet upstream of Detroit Road	+581	+580	City of Rocky River.
	Approximately 1,400 feet downstream of I–90	+594	+595	

Flooding source(s)	Location of referenced elevation **	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL)		Communities affected
		Effective	Modified	
Tinkers Creek Tributary 1	Approximately 0.3 miles upstream of Walton Road	None	+930	City of Bedford.
West Branch Rocky River	Approximately 1.1 miles downstream of Water Street	None	+682	City of Olmsted Falls.
	At Sprague Road	None	+753	
West Branch Rocky River	Approximately 1.1 miles downstream of Water Street	+684	+682	Unincorporated Areas of Cuyahoga County.
	Approximately 1,200 feet downstream of Water Street	+695	+693	

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ADDRESSES

City of Bay Village
Maps are available for inspection at 350 Dover Center Road, Bay Village, OH 44140.

City of Bedford
Maps are available for inspection at 165 Center Road, Bedford, OH 44146.

City of Brooklyn
Maps are available for inspection at 7619 Memphis Avenue, Brooklyn, OH 44144.

City of Cleveland
Maps are available for inspection at 601 Lakeside Avenue, Cleveland, OH 44144.

City of Cleveland Heights
Maps are available for inspection at 40 Severance Circle, Cleveland Heights, OH 44118.

City of Garfield Heights
Maps are available for inspection at 5407 Turney Road, Garfield Heights, OH 44125.

City of Lakewood
Maps are available for inspection at 12650 Detroit Avenue, Lakewood, OH 44107.

City of Maple Heights
Maps are available for inspection at 5353 Lee Road, Maple Heights, OH 44137.

City of North Olmsted
Maps are available for inspection at 5200 Dover Center Road, North Olmsted, OH 44070.

City of Olmsted Falls
Maps are available for inspection at 26100 Bagley Road, Olmsted Falls, OH 44138.

City of Parma
Maps are available for inspection at 6611 Ridge Road, Parma, OH 44129.

City of Parma Heights
Maps are available for inspection at 6281 Pearl Road, Parma Heights, OH 44130.

City of Rocky River
Maps are available for inspection at 21012 Hilliard Boulevard, Rocky River, OH 44116.

City of Westlake
Maps are available for inspection at 27700 Hilliard Boulevard, Westlake, OH 44145.

Unincorporated Areas of Cuyahoga County
Maps are available for inspection at 323 Lakeside Avenue, Suite 400, Cleveland, OH 44113.

Village of Linndale
Maps are available for inspection at 4016 West 119th Street, Linndale, OH 44135.

Village of Mayfield
Maps are available for inspection at 6622 Wilson Mills Road, Mayfield, OH 44143.

Village of Moreland Hills
Maps are available for inspection at 4350 S.O.M. Center Road, Moreland Hills, OH 44022.

Brown County, South Dakota, and Incorporated Areas

James River	Approximately 3.8 miles downstream of 147th Street	None	+1275	Unincorporated Areas of Brown County.
	Approximately 6,260 feet upstream of 101st Street	None	+1296	

* National Geodetic Vertical Datum.
\+ North American Vertical Datum.
\# Depth in feet above ground.

Flooding source(s)	Location of referenced elevation **	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL)		Communities affected
		Effective	Modified	

∧ Mean Sea Level, rounded to the nearest 0.1 meter.

** BFEs to be changed include the listed downstream and upstream BFEs, and include BFEs located on the stream reach between the referenced locations above. Please refer to the revised Flood Insurance Rate Map located at the community map repository (see below) for exact locations of all BFEs to be changed.

Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

Unincorporated Areas of Brown County

Maps are available for inspection at 25 Market Street, Aberdeen, SD 57401.

Lake County, Tennessee, and Incorporated Areas

Flooding source(s)	Location of referenced elevation **	Effective	Modified	Communities affected
Mississippi River	From the Dyer/Lake County boundary (River Mile 845).	None	+281	Unincorporated Areas of Lake County, Town of Tiptonville.
	Lake County/New Madrid County, Missouri/Fulton County, Kentucky boundaries (River Mile 907.3).	None	+311	

* National Geodetic Vertical Datum.

+ North American Vertical Datum.

Depth in feet above ground.

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Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

Town of Tiptonville

Maps are available for inspection at the Town Hall, 130 South Court Street, Tiptonville, TN 38079.

Unincorporated Areas of Lake County

Maps are available for inspection at the County Courthouse, 229 Church Street, Tiptonville, TN 38079.

(Catalog of Federal Domestic Assistance No. 97.022, "Flood Insurance.")

Dated: May 13, 2009.

Deborah S. Ingram,

Acting Deputy Assistant Administrator for Mitigation, Mitigation Directorate, Department of Homeland Security, Federal Emergency Management Agency.

[FR Doc. E9–12106 Filed 5–22–09; 8:45 am]

BILLING CODE 9110–12–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

44 CFR Part 67

[Docket ID FEMA–2008–0020; Internal Agency Docket No. FEMA–B–1051]

Proposed Flood Elevation Determinations

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Proposed rule.

SUMMARY: Comments are requested on the proposed Base (1% annual-chance) Flood Elevations (BFEs) and proposed BFE modifications for the communities listed in the table below. The purpose of this notice is to seek general information and comment regarding the proposed regulatory flood elevations for the reach described by the downstream and upstream locations in the table below. The BFEs and modified BFEs are a part of the floodplain management measures that the community is required either to adopt or show evidence of having in effect in order to qualify or remain qualified for participation in the National Flood Insurance Program (NFIP). In addition, these elevations, once finalized, will be used by insurance agents, and others to calculate appropriate flood insurance premium rates for new buildings and the contents in those buildings.

DATES: Comments are to be submitted on or before August 24, 2009.

ADDRESSES: The corresponding preliminary Flood Insurance Rate Map (FIRM) for the proposed BFEs for each community are available for inspection at the community's map repository. The respective addresses are listed in the table below.

You may submit comments, identified by Docket No. FEMA–B–1051, to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–3151, or (e-mail) *bill.blanton@dhs.gov*.

FOR FURTHER INFORMATION CONTACT: William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–3151, or (e-mail) *bill.blanton@dhs.gov*.

SUPPLEMENTARY INFORMATION: The Federal Emergency Management Agency (FEMA) proposes to make determinations of BFEs and modified BFEs for each community listed below, in accordance with section 110 of the Flood Disaster Protection Act of 1973, 42 U.S.C. 4104, and 44 CFR 67.4(a).

These proposed BFEs and modified BFEs, together with the floodplain management criteria required by 44 CFR 60.3, are the minimum that are required. They should not be construed to mean that the community must change any existing ordinances that are more stringent in their floodplain management requirements. The community may at any time enact stricter requirements of its own, or pursuant to policies established by other Federal, State, or regional entities. These proposed elevations are used to meet the floodplain management requirements of the NFIP and are also used to calculate the appropriate flood insurance premium rates for new buildings built after these elevations are made final, and for the contents in these buildings.

Comments on any aspect of the Flood Insurance Study and FIRM, other than the proposed BFEs, will be considered. A letter acknowledging receipt of any comments will not be sent.

National Environmental Policy Act. This proposed rule is categorically excluded from the requirements of 44 CFR part 10, Environmental Consideration. An environmental impact assessment has not been prepared.

Regulatory Flexibility Act. As flood elevation determinations are not within the scope of the Regulatory Flexibility Act, 5 U.S.C. 601–612, a regulatory flexibility analysis is not required.

Executive Order 12866, Regulatory Planning and Review. This proposed rule is not a significant regulatory action under the criteria of section 3(f) of Executive Order 12866, as amended.

Executive Order 13132, Federalism. This proposed rule involves no policies that have federalism implications under Executive Order 13132.

Executive Order 12988, Civil Justice Reform. This proposed rule meets the applicable standards of Executive Order 12988.

List of Subjects in 44 CFR Part 67

Administrative practice and procedure, Flood insurance, Reporting and recordkeeping requirements.

Accordingly, 44 CFR part 67 is proposed to be amended as follows:

PART 67—[AMENDED]

1. The authority citation for part 67 continues to read as follows:

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

§ 67.4 [Amended]

2. The tables published under the authority of § 67.4 are proposed to be amended as follows:

Flooding source(s)	Location of referenced elevation **	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL)		Communities affected
		Effective	Modified	
Jefferson County, Alabama, and Incorporated Areas				
Dry Creek	Approximately 630 feet upstream of Navajo Trail NE	+720	+722	City of Center Point.
	Just upstream of Chalkville Mountain Road	None	+958	
Griffin Brook	Approximately 800 feet upstream of Lakeshore Drive	+634	+631	City of Homewood.
	Approximately 90 feet upstream of Montgomery Highway.	None	+788	
Huckleberry Branch	Approximately 200 feet downstream of Tyler Road	+516	+514	City of Hoover, City of Vestavia Hills.
	Approximately 1,500 feet upstream of Mountain Oaks Drive.	+824	+814	
Little Shades Creek (Cahaba Basin).	Approximately 930 feet upstream of Loch Haven Drive.	+431	+432	City of Hoover, City of Mountain Brook, City of Vestavia Hills.
	Just upstream of Pipe Line Road	+625	+626	
Little Shades Creek (Shades Creek).	Just downstream of Wenonah Oxmoor Road	+515	+514	City of Bessemer, City of Birmingham.
	Approximately 2.3 miles downstream of Alabama Highway 150.	+633	+632	
Patton Creek	Approximately 0.6 miles downstream of Alabama Highway 150.	+424	+423	City of Hoover, City of Vestavia Hills.
	Approximately 310 feet downstream of West Ridge Drive.	+534	+533	
Pinchgut Creek	Approximately 0.7 miles downstream of Watterson Parkway.	+690	+691	City of Birmingham, City of Trussville.
	Approximately 2.0 miles upstream of Gadsden Highway.	+850	+846	
Turkey Creek	Approximately 0.7 miles downstream of Old Bradford Road.	+566	+565	City of Center Point, City of Clay, City of Pinson.
	Approximately 950 feet upstream of Eagle Ridge Drive.	+880	+885	
Unnamed Creek 10	Approximately 515 feet downstream of Main Street	+605	+607	City of Center Point, City of Pinson.
	Approximately 90 feet downstream of Houston Road	+671	+667	
Unnamed Creek 11	Just upstream of Center Point Road	+627	+626	City of Center Point, City of Pinson.
	Approximately, 1610 feet upstream of Green Crest Drive.	+690	+692	

Flooding source(s)	Location of referenced elevation **	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL)		Communities affected
		Effective	Modified	
Unnamed Creek 9	Just downstream of Alabama Highway 151	+591	+590	City of Center Point.
	Just downstream of Pinson Heights Road	+630	+631	
Valley Creek	Approximately 0.5 miles downstream of Power Plant Road.	None	+431	City of Bessemer.
	Approximately 0.5 miles upstream of Power Plant Road.	None	+440	

* National Geodetic Vertical Datum.
+ North American Vertical Datum.
# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.
** BFEs to be changed include the listed downstream and upstream BFEs, and include BFEs located on the stream reach between the referenced locations above. Please refer to the revised Flood Insurance Rate Map located at the community map repository (see below) for exact locations of all BFEs to be changed.

Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

City of Bessemer
Maps are available for inspection at 1800 Third Avenue North, Bessemer, AL 35020.

City of Birmingham
Maps are available for inspection at 710 20th Street North, Birmingham, AL 35203.

City of Center Point
Maps are available for inspection at 2209 Center Point Parkway, Center Point, AL 35215.

City of Clay
Maps are available for inspection at 6757 Old Springville Road, Pinson, AL 35126.

City of Homewood
Maps are available for inspection at 1903 29th Avenue South, Birmingham, AL 35209.

City of Hoover
Maps are available for inspection at 100 Municipal Drive, Hoover, AL 35236.

City of Mountain Brook
Maps are available for inspection at 56 Church Street, Mountain Brook, AL 35213.

City of Pinson
Maps are available for inspection at 4410 Main Street, Pinson, AL 35126.

City of Trussville
Maps are available for inspection at 131 Main Street, Trussville, AL 35173.

City of Vestavia Hills
Maps are available for inspection at 513 Montgomery Highway, Vestavia Hills, AL 35085.

La Plata County, Colorado, and Incorporated Areas

Grimes Creek	Approximately 0.5 miles downstream of County Road 501.	+7674	+7674	Unincorporated Areas of La Plata County.
	Approximately 1,400 feet upstream of West Grimes Creek Road.	+7779	+7776	
Junction Creek	Pleasant Drive in Durango	+6641	+6659	Unincorporated Areas of La Plata County.
	Approximately 0.2 miles upstream of National Forest Boundary.	+6994	+6996	
Los Pinos River	Approximately 1.2 miles downstream of Highway 160B.	+6829	+6826	Unincorporated Areas of La Plata County.
	Upstream Limit of Detailed Study at Vallecito Reservoir Dam.	None	+7533	
Los Pinos River	Approximately 1,200 feet downstream of Highway 160B.	+6865	+6863	Town of Bayfield.
	Downstream face of Highway 160 Bridge	+6891	+6895	
Middle Creek	Approximately 0.6 miles downstream of County Road 501.	+7674	+7674	Unincorporated Areas of La Plata County.
	West Grimes Creek Road	+7718	+7717	
Vallecito Creek	Approximately 0.5 miles downstream of County Road 501.	+7674	+7674	Unincorporated Areas of La Plata County.
	Vallecito Campground/National Forest Boundary	+7922	+7918	

* National Geodetic Vertical Datum.
+ North American Vertical Datum.
# Depth in feet above ground.

Flooding source(s)	Location of referenced elevation **	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL)		Communities affected
		Effective	Modified	

∧ Mean Sea Level, rounded to the nearest 0.1 meter.

** BFEs to be changed include the listed downstream and upstream BFEs, and include BFEs located on the stream reach between the referenced locations above. Please refer to the revised Flood Insurance Rate Map located at the community map repository (see below) for exact locations of all BFEs to be changed.

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ADDRESSES

Town of Bayfield

Maps are available for inspection at P.O. Box 80, Bayfield, CO 81122.

Unincorporated Areas of La Plata County

Maps are available for inspection at 1060 East 2nd Avenue, Durango, CO 81301.

Will County, Illinois, and Incorporated Areas

Des Plaines River	Approximately 2,700 feet downstream of McKinley Woods Road (extended).	+511	+510	Village of Channahon, City of Joliet, Unincorporated Areas of Will County.
	Brandon Road Lock and Dam	+515	+512	
DuPage River	At confluence with Des Plaines River	+512	+511	Village of Channahon, Unincorporated Areas of Will County.
	Approximately 2,700 feet downstream of Bridge Street.	+512	+511	
Illinois & Michigan Canal (backwater from Des Plaines River).	The area surrounded in a clockwise direction by Hickory Creek, Des Plaines River, Interstate 80, and 250 feet east of Joliet Street.	None	#3	City of Joliet, Unincorporated Areas of Will County.
Illinois & Michigan Canal (backwater from Des Plaines River).	The area surrounded in a clockwise direction by Interstate 80, Des Plaines River, approximately 900 feet north of Columbia Street, and Eastern Avenue.	None	#1	City of Joliet.
Jackson Creek	At confluence of Jackson Creek and Jackson Branch Creek.	None	+627	Village of Frankfort, Unincorporated Areas of Will County.
	104th Avenue	None	+752	
Rock Run South	At confluence with Des Plaines River	+513	+512	City of Joliet.
	Approximately 2,325 feet downstream of U.S. Route 6	+513	+512	

* National Geodetic Vertical Datum.

+ North American Vertical Datum.

Depth in feet above ground.

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Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

City of Joliet

Maps are available for inspection at City Hall, 150 West Jefferson Street, Joliet, IL 60432.

Unincorporated Areas of Will County

Maps are available for inspection at the Will County Land Use Department, 58 East Clinton Street, Joliet, IL 60432.

Village of Channahon

Maps are available for inspection at the Channahon Village Hall, 24555 South Navajo Drive, Channahon, IL 60410.

Village of Frankfort

Maps are available for inspection at the Frankfort Village Hall, 432 West Nebraska Street, Frankfort, IL 60423.

Jones County, Mississippi, and Incorporated Areas

Tallahala Creek	Approximately 800 feet upstream of Luther Hill Road	None	+219	City of Laurel, Unincorporated Areas of Jones County.
	Approximately 1,000 feet upstream of U.S. Highway 84.	None	+228	

* National Geodetic Vertical Datum.

+ North American Vertical Datum.

Depth in feet above ground.

Flooding source(s)	Location of referenced elevation **	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL)		Communities affected
		Effective	Modified	

∧ Mean Sea Level, rounded to the nearest 0.1 meter.

** BFEs to be changed include the listed downstream and upstream BFEs, and include BFEs located on the stream reach between the referenced locations above. Please refer to the revised Flood Insurance Rate Map located at the community map repository (see below) for exact locations of all BFEs to be changed.

Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

City of Laurel

Maps are available for inspection at the City Clerk's Office, 401 North 5th Avenue, Laurel, MS 39440.

Unincorporated Areas of Jones County

Maps are available for inspection at the Jones County Courthouse, 415 North 5th Avenue, Laurel, MS 39440.

Lincoln County, Mississippi, and Incorporated Areas

Flooding source(s)	Location of referenced elevation **	Effective	Modified	Communities affected
Stream 2	Approximately 800 feet downstream of Williams Street.	None	+444	Lincoln County.
Stream 5	Approximately 850 feet downstream of railroad	None	+464	Lincoln County.
Stream 6	Approximately 1,100 feet downstream of North Jackson Street.	None	+465	Lincoln County.

* National Geodetic Vertical Datum.

+ North American Vertical Datum.

Depth in feet above ground.

∧ Mean Sea Level, rounded to the nearest 0.1 meter.

** BFEs to be changed include the listed downstream and upstream BFEs, and include BFEs located on the stream reach between the referenced locations above. Please refer to the revised Flood Insurance Rate Map located at the community map repository (see below) for exact locations of all BFEs to be changed.

Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

Lincoln County

Maps are available for inspection at 300 South 2nd Street, Brookhaven, MS 39601.

Sequatchie County, Tennessee, and Incorporated Areas

Flooding source(s)	Location of referenced elevation **	Effective	Modified	Communities affected
Big Brush Creek	At the confluence with Sequatchie River	None	+702	Sequatchie County.
	Just upstream of Union Road	None	+784	
Little Brush Creek	Approximately 0.4 miles downstream of Old Union Road.	None	+791	Sequatchie County.
	Approximately 588 feet upstream of Old Union Road	None	+825	
Sequatchie River	Just downstream of U.S. Highway 127	None	+690	Sequatchie County.
	Approximately 651 feet upstream of the confluence with Big Brush Creek.	None	+702	

* National Geodetic Vertical Datum.

+ North American Vertical Datum.

Depth in feet above ground.

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Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSESS

Sequatchie County

Maps are available for inspection at the County Courthouse, 307 Cherry Street East, Dunlap, TN 37327.

(Catalog of Federal Domestic Assistance No. 97.022, ''Flood Insurance.'')

Dated: May 14, 2009.

Deborah S. Ingram,

Acting Deputy Assistant Administrator for Mitigation, Mitigation Directorate, Department of Homeland Security, Federal Emergency Management Agency.

[FR Doc. E9–12108 Filed 5–22–09; 8:45 am]

BILLING CODE 9110–12–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

44 CFR Part 67

[Docket ID FEMA–2008–0020; Internal Agency Docket No. FEMA–B–1049]

Proposed Flood Elevation Determinations

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Proposed rule.

SUMMARY: Comments are requested on the proposed Base (1% annual-chance) Flood Elevations (BFEs) and proposed BFE modifications for the communities listed in the table below. The purpose of this notice is to seek general information and comment regarding the proposed regulatory flood elevations for the reach described by the downstream and upstream locations in the table below. The BFEs and modified BFEs are a part of the floodplain management measures that the community is required either to adopt or show evidence of having in effect in order to qualify or remain qualified for participation in the National Flood Insurance Program (NFIP). In addition, these elevations, once finalized, will be used by insurance agents, and others to calculate appropriate flood insurance premium rates for new buildings and the contents in those buildings.

DATES: Comments are to be submitted on or before August 24, 2009.

ADDRESSES: The corresponding preliminary Flood Insurance Rate Map (FIRM) for the proposed BFEs for each community are available for inspection at the community's map repository. The respective addresses are listed in the table below.

You may submit comments, identified by Docket No. FEMA–B–1049, to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–3151, or (e-mail) *bill.blanton@dhs.gov.*

FOR FURTHER INFORMATION CONTACT: William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–3151, or (e-mail) *bill.blanton@dhs.gov.*

SUPPLEMENTARY INFORMATION: The Federal Emergency Management Agency (FEMA) proposes to make determinations of BFEs and modified BFEs for each community listed below, in accordance with section 110 of the Flood Disaster Protection Act of 1973, 42 U.S.C. 4104, and 44 CFR 67.4(a).

These proposed BFEs and modified BFEs, together with the floodplain management criteria required by 44 CFR 60.3, are the minimum that are required. They should not be construed to mean that the community must change any existing ordinances that are more stringent in their floodplain management requirements. The community may at any time enact stricter requirements of its own, or pursuant to policies established by other Federal, State, or regional entities. These proposed elevations are used to meet the floodplain management requirements of the NFIP and are also used to calculate the appropriate flood insurance premium rates for new buildings built after these elevations are made final, and for the contents in these buildings.

Comments on any aspect of the Flood Insurance Study and FIRM, other than the proposed BFEs, will be considered. A letter acknowledging receipt of any comments will not be sent.

National Environmental Policy Act. This proposed rule is categorically excluded from the requirements of 44 CFR part 10, Environmental Consideration. An environmental impact assessment has not been prepared.

Regulatory Flexibility Act. As flood elevation determinations are not within the scope of the Regulatory Flexibility Act, 5 U.S.C. 601–612, a regulatory flexibility analysis is not required.

Executive Order 12866, Regulatory Planning and Review. This proposed rule is not a significant regulatory action under the criteria of section 3(f) of Executive Order 12866, as amended.

Executive Order 13132, Federalism. This proposed rule involves no policies that have federalism implications under Executive Order 13132.

Executive Order 12988, Civil Justice Reform. This proposed rule meets the applicable standards of Executive Order 12988.

List of Subjects in 44 CFR Part 67

Administrative practice and procedure, Flood insurance, Reporting and recordkeeping requirements.

Accordingly, 44 CFR part 67 is proposed to be amended as follows:

PART 67—[AMENDED]

1. The authority citation for part 67 continues to read as follows:

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

§ 67.4 [Amended]

2. The tables published under the authority of § 67.4 are proposed to be amended as follows:

Flooding source(s)	Location of referenced elevation**	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL)		Communities affected
		Effective	Modified	
Greene County, Alabama, and Incorporated Areas				
Boligee Canal	Approximately 1,372 feet downstream of County Road 81.	None	+117	City of Boligee.
	Approximately 193 feet upstream of County Road 81	None	+117	
Tombigbee River	Approximately 2.97 miles upstream of I–20	None	+117	City of Boligee.

Flooding source(s)	Location of referenced elevation**	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL)		Communities affected
		Effective	Modified	

* National Geodetic Vertical Datum.
+ North American Vertical Datum.
# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.
** BFEs to be changed include the listed downstream and upstream BFEs, and include BFEs located on the stream reach between the referenced locations above. Please refer to the revised Flood Insurance Rate Map located at the community map repository (see below) for exact locations of all BFEs to be changed.

Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

City of Boligee

Maps are available for inspection at 8 City Hall Circle, Boligee, AL 35443.

Flooding source(s)	Location of referenced elevation**	Effective	Modified	Communities affected
Mesa County, Colorado, and Incorporated Areas				
Gold Star Canyon	Just above the confluence with Colorado River	None	+4518	Unincorporated Areas of Mesa County, City of Grand Junction.
	Just upstream of South Broadway	None	+4805	
Kannah Creek	Just above the confluence with Indian Creek	None	+4766	Unincorporated Areas of Mesa County.
	Approximately 320 feet upstream of Upper Kannah Creek Road.	None	+6093	
Kannah Creek Lower Split Flow.	Just above confluence with Kannah Creek	None	+4806	Unincorporated Areas of Mesa County.
	Just below divergence from Kannah Creek	None	+4826	
Kannah Creek Upper Split Flow.	Just above confluence with Kannah Creek	None	+4894	Unincorporated Areas of Mesa County.
	Just below divergence from Kannah Creek	None	+4935	
Red Canyon	Just above confluence with Colorado River	None	+4546	Unincorporated Areas of Mesa County, City of Grand Junction.
	Approximately 5,670 feet above South Camp Road	None	+5020	

* National Geodetic Vertical Datum.
+ North American Vertical Datum.
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Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

City of Grand Junction

Maps are available for inspection at 250 North 5th Street, Grand Junction, CO 81501.

Unincorporated Areas of Mesa County

Maps are available for inspection at 544 Rood Avenue, Grand Junction, CO 81502.

Flooding source(s)	Location of referenced elevation**	Effective	Modified	Communities affected
Willow Creek	At Confluence with Blue River	+8681	+8682	Town of Silverthorne, Unincorporated Areas of Summit County.
	Approximately 1,235 feet upstream of Ruby Road	+8873	+8874	

* National Geodetic Vertical Datum.
+ North American Vertical Datum.
# Depth in feet above ground.
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ADDRESSES

Town of Silverthorne

Maps are available for inspection at 601 Center Circle, Silverthorne, CO 80493.

Flooding source(s)	Location of referenced elevation**	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) Effective	Modified	Communities affected

Unincorporated Areas of Summit County

Maps are available for inspection at 208 East Lincoln, Breckenridge, CO 80424–0068.

Cobb County, Georgia, and Incorporated Areas

Chattahoochee River	Above Morgan Falls Dam	+851	+854	Unincorporated Areas of Cobb County.
	Approximately 1,000 feet downstream from confluence of Willeo Creek.	+861	+862	

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\+ North American Vertical Datum.
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ADDRESSES

Unincorporated Areas of Cobb County

Maps are available for inspection at 100 Cherokee Street, Marietta, GA 30090.

Fulton County, Georgia, and Incorporated Areas

Autry Mill Creek	Backwater from Chattahoochee River	*891	*889	City of Johns Creek.
Chattahoochee River	Upstream of Morgan Falls Dam	*857	*854	Unincorporated Areas of Fulton County, City of Johns Creek, City of Roswell, City of Sandy Springs.
	Just downstream of McGinnis Ferry Road	None	*907	
Johns Creek	At confluence with Chattahoochee River	*891	*890	City of Johns Creek.

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\+ North American Vertical Datum.
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ADDRESSES

City of Johns Creek

Maps are available for inspection at 1200 Findley Road, Suite 400, Johns Creek, GA 30097.

City of Roswell

Maps are available for inspection at 38 Hill Street, Roswell, GA 30075.

City of Sandy Springs

Maps are available for inspection at 7840 Roswell Road, Sandy Springs, GA 30350.

Unincorporated Areas of Fulton County

Maps are available for inspection at 141 Pryor Street, Suite 10044, Atlanta, GA 30303.

Chattahoochee River	Just upstream of McGinnis Ferry Road	+911	+908	Unincorporated Areas of Forsyth County.
	Just downstream of Buford Dam	+920	+921	
Dick Creek	At confluence with Chattahoochee River	+913	+909	Unincorporated Areas of Forsyth County.
James Creek	At confluence with Chattahoochee River	+918	+916	Unincorporated Areas of Forsyth County.

* National Geodetic Vertical Datum.
\# Depth in feet above ground.
\+ North American Vertical Datum.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.

Flooding source(s)	Location of referenced elevation**	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL)		Communities affected
		Effective	Modified	

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ADDRESSES

Unincorporated Areas of Forsyth County

Maps are available for inspection at 110 East Main Street, Cumming, GA 30040.

Gwinnett County, Georgia, and Incorporated Areas

Flooding source(s)	Location of referenced elevation**	Effective	Modified	Communities affected
Brushy Creek	At confluence with Chattahoochee River	+909	+906	Unincorporated Areas of Gwinnett County.
Chattahoochee River	Just above Holcomb Bridge Road	+885	+884	City of Sugar Hill, City of Berkeley Lake, City of Duluth, City of Suwanee, Unincorporated Areas of Gwinnett County.
	Approximately 4,000 feet downstream from Buford Dam.	+919	+920	
Level Creek	At confluence with Chattahoochee River	+914	+911	Unincorporated Areas of Gwinnett County.
Mill Creek (Stream 6)	At confluence with Chattahoochee River	+898	+895	City of Berkeley Lake, Unincorporated Areas of Gwinnett County.
Richland Creek	At confluence with Chattahoochee River	+918	+917	Unincorporated Areas of Gwinnett County.
Rogers Creek	At confluence with Chattahoochee River	+902	+899	City of Duluth, Unincorporated Areas of Gwinnett County.
Stream 1	At confluence with Chattahoochee River	+887	+886	Unincorporated Areas of Gwinnett County.
Stream 10	At confluence with Chattahoochee River	+907	+903	Unincorporated Areas of Gwinnett County.
Stream 2	At confluence with Chattahoochee River.	+888	+887	Unincorporated Areas of Gwinnett County.
Stream 3	At confluence with Chattahoochee River	+891	+889	Unincorporated Areas of Gwinnett County.
Stream 4	At confluence with Chattahoochee River	+893	+891	Unincorporated Areas of Gwinnett County.
Stream 5	At confluence with Chattahoochee River	+897	+894	Unincorporated Areas of Gwinnett County.
Stream 8	At confluence with Chattahoochee River	+900	+897	City of Duluth, Unincorporated Areas of Gwinnett County.
Suwanee Creek	At confluence with Chattahoochee River	+908	+905	Unincorporated Areas of Gwinnett County.
Swilling Creek	At confluence with Chattahoochee River	+899	+896	City of Duluth, Unincorporated Areas of Gwinnett County.

* National Geodetic Vertical Datum.
+ North American Vertical Datum.
# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.

** BFEs to be changed include the listed downstream and upstream BFEs, and include BFEs located on the stream reach between the referenced locations above. Please refer to the revised Flood Insurance Rate Map located at the community map repository (see below) for exact locations of all BFEs to be changed.

Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

City of Berkeley Lake

Maps are available for inspection at 4040 South Berkeley Road, Northwest, Berkeley Lake, GA 30096.

City of Duluth

Maps are available for inspection at 3167 Main Street, 2nd Floor, Duluth, GA.

City of Sugar Hill

Flooding source(s)	Location of referenced elevation**	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) Effective	Modified	Communities affected

Maps are available for inspection at 4988 West Broad Street, Sugar Hill, GA 30518.

City of Suwanee

Maps are available for inspection at 373 Highway 23, Suwanee, GA 30024.

Unincorporated Areas of Gwinnett County

Maps are available for inspection at 75 Langley Drive, Lawrenceville, GA 30045.

Lafourche Parish, Louisiana, and Incorporated Areas

Flooding source(s)	Location of referenced elevation**	Effective	Modified	Communities affected
Gulf of Mexico	From the west at the Terrebonne Parish border along the shoreline of the Gulf of Mexico to the south. To the east border of Jefferson Parish and St. Charles Parish and to the northern border of St. James Parish and St. John the Baptist Parish.	+2–12	+2–18	Unincorporated Areas of Lafourche Parish, City of Raceland, City of Thibodaux, Town of Golden Meadow, Town of Lockport.

* National Geodetic Vertical Datum.
\+ North American Vertical Datum.
\# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.
** BFEs to be changed include the listed downstream and upstream BFEs, and include BFEs located on the stream reach between the referenced locations above. Please refer to the revised Flood Insurance Rate Map located at the community map repository (see below) for exact locations of all BFEs to be changed.

Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

City of Raceland

Maps are available for inspection at P.O. Box 5548, Thibodaux, LA 70302.

City of Thibodaux

Maps are available for inspection at P.O. Box 5418, Thibodaux, LA 70302.

Town of Golden Meadow

Maps are available for inspection at P.O. Box 307, Golden Meadow, LA 70357.

Town of Lockport

Maps are available for inspection at 710 Church Street, Lockport, LA 70374.

Unincorporated Areas of Lafourche Parish

Maps are available for inspection at 402 Green Street, Thibodaux, LA 70302.

Rolette County, North Dakota, and Incorporated Areas

Flooding source(s)	Location of referenced elevation**	Effective	Modified	Communities affected
Ox Creek	501 feet upstream of Belcourt Southern Corporate Limit.	None	+1903	Chippewa Indian Reservation, Turtle Mountain Band.
	27 feet downstream of Belcourt Lake	None	+2015	
Ox Creek Breakout	100 feet upstream of 99th Street NE	None	+1971	Chippewa Indian Reservation, Turtle Mountain Band.
	2,154 feet upstream of 99th Street NE	None	+1972	

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\+ North American Vertical Datum.
\# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.
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Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

Chippewa Indian Reservation, Turtle Mountain Band

Maps are available for inspection at Highway 5 West, Belcourt, ND 58316.

Lucas County, Ohio, and Incorporated Areas

Flooding source(s)	Location of referenced elevation**	Effective	Modified	Communities affected
Barnum Ditch	Just above the confluence with Tifft Ditch	None	+617	City of Toledo.
	Approximately 350 feet downstream of Willis Boulevard.	None	+626	

Flooding source(s)	Location of referenced elevation**	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL)		Communities affected
		Effective	Modified	
Blue Creek	Approximately 1,100 feet upstream of Finzel Road	+641	+640	Village of Whitehouse, Unincorporated Areas of Lucas County.
	Downstream side of Fulton Lucas Road	None	+665	
Blystone Ditch	Upstream side of Dutch Road	+645	+644	Village of Waterville, Unincorporated Areas of Lucas County.
	Downstream side of Bluebird Train Railroad	None	+659	
Comstock Ditch	Upstream side of Brint Road	None	+675	Unincorporated Areas of Lucas County.
	Downstream side of Mitchaw Road	None	+679	
Crane Creek	Approximately 0.6 mile downstream of Nissen Road	None	+579	Unincorporated Areas of Lucas County.
	Approximately 2,000 feet upstream of Ofper Lentz Road.	None	+584	
Deline Ditch	At the confluence with Heldman Ditch (East)	+601	+606	City of Toledo
	Downstream side of Hill Avenue	+627	+629	
Deline Ditch Overflow	At the confluence with Deline Ditch	None	+614	City of Toledo.
	Just below the divergence from Deline Ditch	None	+625	
Dennis Ditch	At the confluence with Heldman Ditch (East)	+597	+604	City of Toledo.
	Approximately 875 feet upstream of South Avenue	+624	+623	
Detwiler Ditch	Upstream side of Summit Street	None	+578	City of Toledo.
	Approximately 0.56 mile upstream of I–280	None	+578	
Disher Ditch	Upstream side of Rupp Road	+641	+640	Village of Whitehouse, Unincorporated Areas of Lucas County.
	Downstream side of Berkey Southern Highway	None	+657	
Disher Ditch Overflow	At the confluence with Blue Creek	None	+640	Village of Whitehouse.
	Downstream side of Heller Road	None	+653	
Duck Creek	At mouth at Maumee Bay	None	+578	City of Oregon, City of Toledo.
	Downstream side of Consaul Street	None	578	
Eisenbraum Ditch	Approximately 175 feet downstream of Elsie Avenue	+619	+618	City of Toledo.
	Downstream side of West Alexis Highway	+650	+651	
Good Ditch	South of Angola Road near Holland Park Boulevard	None	+633	Village of Holland.
	South of Angola Road approximately 60 feet west of Holland Park Boulevard.	None	+633	
Haefner Ditch	At the confluence with Hill Ditch	+597	+604	City of Toledo, Unincorporated Areas of Lucas County.
	Downstream side of I–475	+637	+638	
Heldman Ditch (East)	Downstream side of Edgevale Road	None	+594	City of Toledo, Unincorporated Areas of Lucas County, Village of Ottawa Hills.
	Downstream side of West Bancroft Street	+666	+665	
Heldman Ditch (West)	At the confluence with Prairie Ditch	+669	+668	Unincorporated Areas of Lucas County.
	Downstream side of North Crissey Road	+669	+668	
Hill Ditch	At the confluence with Heldman Ditch (East)	+597	+604	City of Toledo, Unincorporated Areas of Lucas County.
	Just below the confluence with Smith	+640	+639	
Jamieson Ditch	At the confluence with Silver Creek	+592	+595	City of Toledo.
	Downstream side of Lewis Avenue	+601	+600	
Ketcham Ditch	Approximately 700 feet downstream of Jackman Road.	+607	+609	City of Toledo.
	Downstream side of Adella Street	+618	+619	
Lone Oak Ditch	Upstream side of Winslow Road	None	+644	Village of Whitehouse, Unincorporated Areas of Lucas County.
	Approximately 70 feet downstream of Berkey Southern Highway.	None	+657	
Maumee Bay	West of the mouth of Driftmeyer Ditch	+579	+578	City of Oregon, City of Toledo.
	At the northern boundary of Lucas County	+579	+578	
Maumee River	At mouth at Maumee Bay	+579	+578	City of Toledo.
	Upstream side of Norfolk Southern Railroad	+579	+578	

Flooding source(s)	Location of referenced elevation**	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL)		Communities affected
		Effective	Modified	
Mayer Ditch	Downstream side of I–475	None	+636	Unincorporated Areas of Lucas County.
	Approximately 475 feet downstream of Dorr Street	None	+639	
McPeak Ditch	Approximately 100 feet above the confluence with Tenmile Creek.	+647	+646	City of Sylvania.
	Approximately 1,300 feet upstream of Winding Way	+667	+668	
Mud Creek	At the confluence with Detwiler Creek	None	+578	City of Toledo.
	Downstream side of Hoffman Road	None	+578	
North Branch Ketcham Ditch	Downstream side of Douglas Road	None	+620	City of Toledo.
	Approximately 650 feet upstream of Secor Road	None	+631	
Ottawa River	Approximately 0.91 mile downstream of Summit Street.	+579	+578	City of Oregon, City of Toledo.
	Downstream side of CSX Transportation Railroad	+579	+578	
Otter Creek	Downstream side of Corduroy Road	None	+578	City of Toledo.
	At mouth at Maumee Bay	+579	+578	
	Upstream side of CSX Transportation Railroad	None	+589	
	Approximately 350 feet upstream of CSX Transportation Railroad.	None	+589	
	Upstream side of CSX Transportation Railroad	None	+590	
	Approximately 475 feet downstream of Dover Place	None	+590	
Peterson Ditch	Upstream side of Haughton Drive	+613	+614	City of Toledo.
	Approximately 100 feet upstream of Goddard Road	+614	+615	
Potter Ditch	At the confluence with Heldman Ditch (East)	+634	+635	City of Toledo, Unincorporated Areas of Lucas County.
	Downstream side of Derbyshire Road	+634	+635	
Schmitz Ditch	At the confluence with Tenmile Creek	None	+694	Village of Berkey.
	Downstream side of Lathrop Road	None	+707	
Schneider Ditch	Just above the confluence with Williams Ditch	+619	+621	City of Toledo.
	Downstream side of Hill Avenue	+620	+621	
Shantee Creek	At the confluence with Silver Creek	+582	+583	City of Toledo, Unincorporated Areas of Lucas County.
	Approximately 225 feet upstream of Tremainsville Road.	+614	+612	
	Approximately 1,100 feet downstream of Summit Street.	+579	+578	
	Approximately 300 feet downstream of Hagman Road	+579	+578	
Shantee Creek Overflow Channel 1.	Approximately 175 feet upstream of Lewis Avenue	None	+599	City of Toledo.
	Just below the divergence from Shantee Creek	None	+611	
Shantee Creek Overflow Channel 2.	At the confluence with Shantee Creek	None	+599	City of Toledo.
	Approximately 100 feet downstream of Jackman Road.	None	+609	
Sharp Ditch	Upstream side of Brint Road	None	+679	Unincorporated Areas of Lucas County.
	Approximately 1.0 mile upstream of Brint Road	None	+683	
Silver Creek	Upstream side of CN North America Railroad	+579	+578	Unincorporated Areas of Lucas County, City of Toledo.
	Approximately 100 feet upstream of Woodview Drive	None	+639	
Smith Ditch South	At the confluence with Hill Ditch	+640	+639	Unincorporated Areas of Lucas County.
	Approximately 200 feet upstream of Wimbledon Park Boulevard.	+660	+661	
South Branch Silver Creek	At the confluence with Silver Creek	None	+628	City of Toledo.
	Approximately 1,150 feet upstream of Rambo Lane	None	+633	
Tenmile Creek	Upstream side of Herr Road	+669	+668	Village of Berkey, Unincorporated Areas of Lucas County.
	Downstream side of North Fulton Lucas Road	None	+708	
Tifft Ditch	Approximately 225 feet upstream of Tremainsville Road.	+614	+612	City of Toledo, Unincorporated Areas of Lucas County.
	Approximately 300 feet upstream of Talmadge Road	+633	+634	
Vanderpool Ditch	Downstream side of McCord Road	+642	+644	Unincorporated Areas of Lucas County.

Flooding source(s)	Location of referenced elevation**	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL)		Communities affected
		Effective	Modified	
	Approximately 375 feet downstream of King Road	+657	+656	
Williams Ditch	Upstream side of Norfolk Southern Railroad	+613	+614	City of Toledo.
	Approximately 175 feet downstream of Hill Avenue	+619	+621	
Wing Ditch	Just above confluence with Silver Creek	None	+633	City of Toledo.
	Approximately 75 feet downstream of Merle Street	None	+637	

*National Geodetic Vertical Datum.
+North American Vertical Datum.
Depth in feet above ground.
∧Mean Sea Level, rounded to the nearest 0.1 meter.

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Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

City of Oregon
Maps are available for inspection at 5330 Seaman Road, Oregon, OH 43616.

City of Sylvania
Maps are available for inspection at 6730 Monroe Street, Suite 101, Sylvania, OH 43560.

City of Toledo
Maps are available for inspection at One Government Center, Suite 1600, Toledo, OH 43604.

Unincorporated Areas of Lucas County
Maps are available for inspection at 1115 South McCord Road, Holland, OH 43528.

Village of Berkey
Maps are available for inspection at 12360 Sylvania-Metamora Road, Berkey, OH 45304.

Village of Holland
Maps are available for inspection at 1245 Clarion Avenue, Holland, OH 43528.

Village of Ottawa Hills
Maps are available for inspection at 2125 Richards Road, Toledo, OH 43606.

Village of Waterville
Maps are available for inspection at 25 North Second Street, Waterville, OH 43566.

Village of Whitehouse
Maps are available for inspection at 6925 Providence Street, Whitehouse, OH 43571.

Ottawa County, Oklahoma, and Incorporated Areas

Belmont Run	Approximately 1,317 feet upstream of 30th Avenue	None	+803	City of Miami, Town of North Miami, Unincorporated Areas of Ottawa County.
	Approximately 1,288 feet upstream of Newman Road	None	+805	
Fairgrounds Branch	Approximately 700 feet upstream of E Street	None	+774	Unincorporated Areas of Ottawa County.
	Approximately 0.58 miles upstream of E Street	None	+774	
Neosho River	Just upstream of E Street	None	+775	Unincorporated Areas of Ottawa County.
	Approximately 0.93 miles upstream from State Highway 69.	None	+776	
Warren Branch	Approximately 434 feet upstream of Main Street	None	+869	Town of Peoria, Unincorporated Areas of Ottawa County.
	Approximately 1,826 feet upstream of Modoe Street	None	+885	
Wyandotte Ditch	Approximately 1,320 feet downstream of Main Street	+756	+757	Town of Wyandotte.
	Approximately 904 feet upstream of South 650 Road	+780	+789	

* National Geodetic Vertical Datum.
+ North American Vertical Datum.
# Depth in feet above ground.
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Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

Flooding source(s)	Location of referenced elevation**	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) Effective	Modified	Communities affected

ADDRESSES

City of Miami

Maps are available for inspection at the Civic Center, 129 5th Street, Northwest, Miami, OK 74354.

Town of North Miami

Maps are available for inspection at the Ottawa County Courthouse, 102 East Central Avenue, Suite 202, Miami, OK 74354.

Town of Peoria

Maps are available for inspection at the Ottawa County Courthouse, 102 East Central Avenue, Suite 202, Miami, OK 74354.

Town of Wyandotte

Maps are available for inspection at City Hall, 14 North Main Street, Wyandotte, OK 74370.

Unincorporated Areas of Ottawa County

Maps are available for inspection at the Ottawa County Courthouse, 102 East Central Avenue, Suite 202, Miami, OK 74354.

Umatilla County, Oregon, and Incorporated Areas

Flooding source(s)	Location of referenced elevation**	Effective	Modified	Communities affected
Iskuupla Creek	At confluence with Umatilla River	None	+1690	Umatilla Indian Reservation.
	Approximately 1.0 mile upstream from Bingham Road	None	+1779	
Iskuupla Creek left bank split	Approximately 3,000 feet west along Bingham Road from Iskuupla Creek.	None	+1682	Umatilla Indian Reservation.
	At divergence from Iskuupla Creek	None	+1707	
Meacham Creek	At confluence with Umatilla River	None	+1762	Umatilla Indian Reservation.
	Just downstream of Meacham Creek Road Bridge and Railroad Bridge.	None	+1819	
Umatilla River	Just upstream of State Highway 11 Bridge	+1106	+1111	City of Pendleton, Umatilla Indian Reservation, Unincorporated Areas of Umatilla County.
	Approximately 700 feet downstream of confluence of Ryan Creek.	None	+1908	
Walla-Walla River	At SE 17th Avenue	None	#1	City of Milton-Freewater, Unincorporated Areas of Umatilla County.
	At NE 15th Avenue	None	#1	
Wildhorse Creek	At Range line 32E/33E	None	+1142	Unincorporated Areas of Umatilla County.
	At Township line 2N/3N	None	+1154	

* National Geodetic Vertical Datum.
+ North American Vertical Datum.
# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.
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ADDRESSES

City of Milton-Freewater

Maps are available for inspection at 722 South Main Street, Milton-Freewater, OR 97862.

City of Pendleton

Maps are available for inspection at 500 Southwest Dorion Avenue, Pendleton, OR 97801.

Umatilla Indian Reservation

Maps are available for inspection at 73239 Confederated Way, Pendleton, OR 97801.

Unincorporated Areas of Umatilla County

Maps are available for inspection at 216 Southeast 4th Street, Pendleton, OR 97801.

Spartanburg County, South Carolina, and Incorporated Areas

Flooding source(s)	Location of referenced elevation**	Effective	Modified	Communities affected
Jimmies Creek (North)	Approximately 125 feet downstream of Tucapau Road	None	+779	City of Wellford.
	Approximately 2,190 feet upstream of Tucapau Road	None	+789	
Little Buck Creek	Approximately 750 feet downstream of Richland Street.	None	+809	City of Chesnee.
	Approximately 280 feet upstream of Cherokee Street	None	+841	
Little Buck Creek Tributary 1	Confluence with Little Buck Creek	None	+815	City of Chesnee.

Flooding source(s)	Location of referenced elevation**	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL)		Communities affected
		Effective	Modified	
	Approximately 1,100 feet upstream of the confluence with Little Buck Creek.	None	+851	
Pacolet River Tributary 1	Approximately 1,350 feet downstream of Church Street.	None	+731	Town of Cowpens.
	Approximately 290 feet upstream of Church Street	None	+765	

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\+ North American Vertical Datum.
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Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

City of Chesnee
Maps are available for inspection at 201 West Cherokee Street, Chesnee, SC 29323.

City of Wellford
Maps are available for inspection at 127 Syphrit Road, Wellford, SC 29385.

Town of Cowpens
Maps are available for inspection at 530 North Main Street, Cowpens, SC 29330.

Sanborn County, South Dakota, and Incorporated Areas

James River	Approximately 2,133 feet downstream of 243rd Street	None	+1226	Unincorporated Areas of Sanborn County.
	Approximately 1,162 feet upstream of 221st Street	None	+1237	

* National Geodetic Vertical Datum.
\+ North American Vertical Datum.
\# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.
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Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

Unincorporated Areas of Sanborn County
Maps are available for inspection at 604 West 6th Street, Woonsocket, SD 57385.

Val Verde County, Texas, and Incorporated Areas

Calveras Creek	Confluence with San Felipe Creek	None	+924	Unincorporated Areas of Val Verde County.
	Approximately 0.6 miles upstream of Gilberto Road	None	+1015	
Cantu Branch	Just upstream of Dodson Avenue	None	+1035	Unincorporated Areas of Val Verde County.
	Approximately 1,222 feet upstream from Grace Drive	None	+1046	
San Felipe Creek	Just upstream of Gilchrist Lane	None	+911	Unincorporated Areas of Val Verde County.
	Just upstream of River Road	None	+929	

* National Geodetic Vertical Datum.
\+ North American Vertical Datum.
\# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.
** BFEs to be changed include the listed downstream and upstream BFEs, and include BFEs located on the stream reach between the referenced locations above. Please refer to the revised Flood Insurance Rate Map located at the community map repository (see below) for exact locations of all BFEs to be changed.
Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

Flooding source(s)	Location of referenced elevation**	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL)		Communities affected
		Effective	Modified	

ADDRESSES

Unincorporated Areas of Val Verde County

Maps are available for inspection at the Del Rio City Hall, 109 West Broadway Street, Del Rio, TX 78840.

(Catalog of Federal Domestic Assistance No. 97.022, ''Flood Insurance.'')

Dated: May 14, 2009.

Deborah S. Ingram,

Acting Deputy Assistant Administrator for Mitigation, Mitigation Directorate, Department of Homeland Security, Federal Emergency Management Agency.

[FR Doc. E9–12101 Filed 5–22–09; 8:45 am]

BILLING CODE 9110–12–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

44 CFR Part 67

[Docket ID FEMA–2008–0020; Internal Agency Docket No. FEMA–B–1047]

Proposed Flood Elevation Determinations

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Proposed rule.

SUMMARY: Comments are requested on the proposed Base (1% annual-chance) Flood Elevations (BFEs) and proposed BFE modifications for the communities listed in the table below. The purpose of this notice is to seek general information and comment regarding the proposed regulatory flood elevations for the reach described by the downstream and upstream locations in the table below. The BFEs and modified BFEs are a part of the floodplain management measures that the community is required either to adopt or show evidence of having in effect in order to qualify or remain qualified for participation in the National Flood Insurance Program (NFIP). In addition, these elevations, once finalized, will be used by insurance agents, and others to calculate appropriate flood insurance premium rates for new buildings and the contents in those buildings.

DATES: Comments are to be submitted on or before August 24, 2009.

ADDRESSES: The corresponding preliminary Flood Insurance Rate Map (FIRM) for the proposed BFEs for each community are available for inspection at the community's map repository. The respective addresses are listed in the table below.

You may submit comments, identified by Docket No. FEMA–B–1047, to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–3151, or (e-mail) *bill.blanton@dhs.gov*.

FOR FURTHER INFORMATION CONTACT: William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–3151, or (e-mail) *bill.blanton@dhs.gov*.

SUPPLEMENTARY INFORMATION: The Federal Emergency Management Agency (FEMA) proposes to make determinations of BFEs and modified BFEs for each community listed below, in accordance with section 110 of the Flood Disaster Protection Act of 1973, 42 U.S.C. 4104, and 44 CFR 67.4(a).

These proposed BFEs and modified BFEs, together with the floodplain management criteria required by 44 CFR 60.3, are the minimum that are required. They should not be construed to mean that the community must change any existing ordinances that are more stringent in their floodplain management requirements. The community may at any time enact stricter requirements of its own, or pursuant to policies established by other Federal, State, or regional entities. These proposed elevations are used to meet the floodplain management requirements of the NFIP and are also used to calculate the appropriate flood insurance premium rates for new buildings built after these elevations are made final, and for the contents in these buildings.

Comments on any aspect of the Flood Insurance Study and FIRM, other than the proposed BFEs, will be considered. A letter acknowledging receipt of any comments will not be sent.

National Environmental Policy Act. This proposed rule is categorically excluded from the requirements of 44 CFR part 10, Environmental Consideration. An environmental impact assessment has not been prepared.

Regulatory Flexibility Act. As flood elevation determinations are not within the scope of the Regulatory Flexibility Act, 5 U.S.C. 601–612, a regulatory flexibility analysis is not required.

Executive Order 12866, Regulatory Planning and Review. This proposed rule is not a significant regulatory action under the criteria of section 3(f) of Executive Order 12866, as amended.

Executive Order 13132, Federalism. This proposed rule involves no policies that have federalism implications under Executive Order 13132.

Executive Order 12988, Civil Justice Reform. This proposed rule meets the applicable standards of Executive Order 12988.

List of Subjects in 44 CFR Part 67

Administrative practice and procedure, Flood insurance, Reporting and recordkeeping requirements.

Accordingly, 44 CFR part 67 is proposed to be amended as follows:

PART 67—[AMENDED]

1. The authority citation for part 67 continues to read as follows:

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

§ 67.4 [Amended]

2. The tables published under the authority of § 67.4 are proposed to be amended as follows:

Flooding source(s)	Location of referenced elevation **	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) Effective	Modified	Communities affected
Harvey County, Kansas, and Incorporated Areas				
Sand Creek	Approximately 865 feet upstream of Northeast 24th Street.	+1436	+1434	City of North Newton.
	Approximately 1,590 feet upstream of Northeast 24th Street.	+1437	+1435	

* National Geodetic Vertical Datum.
\+ North American Vertical Datum.
\# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.
** BFEs to be changed include the listed downstream and upstream BFEs, and include BFEs located on the stream reach between the referenced locations above. Please refer to the revised Flood Insurance Rate Map located at the community map repository (see below) for exact locations of all BFEs to be changed.

Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

City of North Newton
Maps are available for inspection at 2601 North Main Street, North Newton, KS 67117.

Flooding source(s)	Location of referenced elevation **	Effective	Modified	Communities affected
Dukes County, Massachusetts, and Incorporated Areas				
Atlantic Ocean	Along the shoreline of the Atlantic Ocean between Gilberts Cove and Quenames Cove.	+7	+11	Town of Chilmark.
Atlantic Ocean	Along the shoreline of the Atlantic Ocean between Paqua Pond and Jobs Neck Pond.	None	+9	Town of Edgartown.
Atlantic Ocean	Along the shoreline of the Atlantic Ocean between Long Cove and Homer Road.	None	+9	Town of West Tisbury.
Vineyard Sound	Along the shoreline of Vineyard Sound approximately 300 feet East of the intersection of Lobsterville Road and West Basin Road.	+8	+9	Town of Aquinnah.
Vineyard Sound	Along the shoreline of Vineyard Sound between Farm Pond and Hamlin Pond.	None	+12	Town of Oak Bluffs.
Vineyard Sound	Along the shoreline of Vineyard Sound between Algonquin Avenue to Yacht Club Lane.	None	+12	Town of Tisbury.

* National Geodetic Vertical Datum.
\+ North American Vertical Datum.
\# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.
** BFEs to be changed include the listed downstream and upstream BFEs, and include BFEs located on the stream reach between the referenced locations above. Please refer to the revised Flood Insurance Rate Map located at the community map repository (see below) for exact locations of all BFEs to be changed.

Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

Town of Aquinnah
Maps are available for inspection at the Town Hall, 65 State Road, Aquinnah, MA 02535.

Town of Chilmark
Maps are available for inspection at the Town Hall, 401 Middle Road, Chilmark, MA 02535.

Town of Edgartown
Maps are available for inspection at the Town Hall, 70 Main Street, Edgartown, MA 02539.

Town of Oak Bluffs
Maps are available for inspection at the Town Hall, 56 School Street, Oak Bluffs, MA 02557.

Town of Tisbury
Maps are available for inspection at the Town Hall, 51 Spring Street, Vineyard Haven, MA 02568.

Town of West Tisbury
Maps are available for inspection at the Town Hall, 1059 State Road, West Tisbury, MA 02575.

Flooding source(s)	Location of referenced elevation **	Effective	Modified	Communities affected
Kennebec County, Maine, and Incorporated Areas				
China Lake	Along the entire shoreline	None	+199	Town of Albion.
China Lake	Along the entire shoreline	None	+199	Town of Vassalboro.
Kezar Brook	At the mouth of Cobboseecontee Lake	None	+169	Town of Winthrop.

Flooding source(s)	Location of referenced elevation **	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) Effective	Modified	Communities affected
	Just downstream of South Road	None	+169	

* National Geodetic Vertical Datum.
+ North American Vertical Datum.
# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.
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Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

Town of Albion
Maps are available for inspection at the Town Office, 22 Main Street, Albion, ME 04910.

Town of Vassalboro
Maps are available for inspection at the Town Hall, 682 Main Street, North Vassalboro, ME 04989.

Town of Winthrop
Maps are available for inspection at the Town Hall, 17 Highland Avenue, Winthrop, ME 04364.

Pike County, Mississippi, and Incorporated Areas

Flooding source(s)	Location of referenced elevation **	Effective	Modified	Communities affected
Tangipahoa River	Approximately 0.68 miles downstream of Highway 575.	None	+233	Town of Osyka.
	Approximately 1,100 feet downstream of Highway 575	None	+236	

* National Geodetic Vertical Datum.
+ North American Vertical Datum.
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Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

Town of Osyka
Maps are available for inspection at 215 West Liberty Street, Osyka, MS 39648.

Muskingum County, Ohio, and Incorporated Areas

Flooding source(s)	Location of referenced elevation **	Effective	Modified	Communities affected
Moxahala Creek	Approximately 1,300 feet downstream of Ransbottom Road.	None	+734	Unincorporated Areas of Muskingum County.
	Approximately 500 feet downstream of East 1st Street	None	+735	
Muskingum River	Approximately 0.4 mile downstream of E Muskingum Avenue (State Route 208).	+714	+718	Village of Dresden.
	At confluence with Wakatomika Creek	+716	+720	
Muskingum River	Approximately 0.6 mile downstream of confluence with Salt Creek.	None	+683	Village of Philo.
	Approximately 0.5 mile upstream of confluence with Salt Creek.	None	+685	
Wakatomika Creek	Approximately 0.5 mile downstream of Main Street	+719	+720	Unincorporated Areas of Muskingum County.
	Approximately 1,400 feet downstream of Frazeysburg Road.	+719	+725	
Wakatomika Creek	Approximately 0.6 mile downstream of Shannon Road	None	+745	Unincorporated Areas of Muskingum County, Village of Frazeysburg.
	Just downstream of Canal Road	None	+751	
Wakatomika Creek	Approximately 0.5 mile downstream of Main Street	None	+720	Village of Dresden.
	Approximately 0.4 mile downstream of Frazeysburg Road.	None	+725	

* National Geodetic Vertical Datum.
+ North American Vertical Datum.
# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.

Flooding source(s)	Location of referenced elevation **	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL)		Communities affected
		Effective	Modified	

** BFEs to be changed include the listed downstream and upstream BFEs, and include BFEs located on the stream reach between the referenced locations above. Please refer to the revised Flood Insurance Rate Map located at the community map repository (see below) for exact locations of all BFEs to be changed.

Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

Unincorporated Areas of Muskingum County

Maps are available for inspection at 401 Main Street, Zanesville, OH 43701.

Village of Dresden

Maps are available for inspection at 904 Chestnut Street, Dresden, OH 43821.

Village of Frazeysburg

Maps are available for inspection at 7 West Second Street, Frazeysburg, OH 43822.

Village of Philo

Maps are available for inspection at 300 Main Street, Philo, OH 43771.

Macon County, Tennessee, and Incorporated Areas

Salt Lick Creek	Approximately 1,965 feet upstream of State Highway 151.	None	+778	Unincorporated Areas of Macon County.
	Approximately 1,624 feet upstream of State Highway 151.	None	+778	

* National Geodetic Vertical Datum.
+ North American Vertical Datum.
# Depth in feet above ground.
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** BFEs to be changed include the listed downstream and upstream BFEs, and include BFEs located on the stream reach between the referenced locations above. Please refer to the revised Flood Insurance Rate Map located at the community map repository (see below) for exact locations of all BFEs to be changed.

Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

Unincorporated Areas of Macon County

Maps are available for inspection at 201 County Courthouse, Lafayette, TN 37083.

Ector County, Texas, and Incorporated Areas

Flooding Effects of Eastside Channel and its Split Flow.	Just downstream of the Pacific Union Railroad	None	+2887	Unincorporated Areas of Ector County, City of Odessa.
	Just downstream of Pueblo Avenue	None	+2906	
	Approximately 200 feet upstream of the intersection of Custer Avenue and Eastside Channel.	None	+2912	
Flooding Effects of Monahans Draw.	Just upstream of Grandview Road	None	+2842	Unincorporated Areas of Ector County.
	Just upstream of South Crane Avenue	None	+2878	
	Just upstream of West County Road	None	+2884	
	Just upstream of Westcliff Drive	None	+3009	
	Just upstream of State Highway 866	None	+3043	
Flooding effects of Far East Channel and its subsidiary channels.	At the confluence of East Side Channel	None	+2857	Unincorporated Areas of Ector County, City of Odessa.
	Approximately 450 feet upstream of the intersection of Caliche Road.	None	+2899	
	Just upstream of Maple Avenue	None	+2907	
Flooding effects of West Side Drainage Channel.	At the confluence of Monahans Draw	None	+2896	City of Odessa.
	Just upstream of West 16th Street	None	+2909	

* National Geodetic Vertical Datum.
+ North American Vertical Datum.
# Depth in feet above ground.
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Flooding source(s)	Location of referenced elevation **	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL)		Communities affected
		Effective	Modified	

Send comments to William R. Blanton, Jr., Chief, Engineering Management Branch, Mitigation Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472.

ADDRESSES

City of Odessa

Maps are available for inspection at 411 West 8th Street, Odessa, TX 79761.

Unincorporated Areas of Ector County

Maps are available for inspection at 521 North Texas Street, Odessa, TX 79761.

(Catalog of Federal Domestic Assistance No. 97.022, "Flood Insurance.")

Dated: May 14, 2009.

Deborah S. Ingram,

Acting Deputy Assistant Administrator for Mitigation, Mitigation Directorate, Department of Homeland Security, Federal Emergency Management Agency.

[FR Doc. E9–12105 Filed 5–22–09; 8:45 am]

BILLING CODE 9110–12–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 679

RIN 0648–AX71

Fisheries of the United States Exclusive Economic Zone Off Alaska; Fisheries of the Arctic Management Area; Bering Sea Subarea

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

ACTION: Availability of a fishery management plan and fishery management plan amendment; request for comments.

SUMMARY: The North Pacific Fishery Management Council has submitted the Fishery Management Plan for Fish Resources of the Arctic Management Area (Arctic FMP) and Amendment 29 to the FMP for Bering Sea/Aleutian Islands King and Tanner Crabs (Crab FMP). The Arctic FMP and Amendment 29 to the Crab FMP, if approved, would establish sustainable management of commercial fishing in the Arctic Management Area and limit the management area of crab species under the Crab FMP to waters of the U.S. Exclusive Economic Zone (EEZ) south of Bering Strait. This action is necessary to establish a management framework for commercial fishing of nearly all fish species occurring in the Arctic Management Area before the potential onset of unregulated commercial fishing in the Arctic Management Area. This action is intended to promote the goals and objectives of the Magnuson–Stevens Fishery Conservation and Management Act, the FMPs, and other applicable laws. Comments from the public are encouraged.

DATES: Written comments on the Arctic FMP and Crab FMP amendment must be received by 1700 hours, A.D.T. on July 27, 2009.

ADDRESSES: Send comments to Sue Salveson, Assistant Regional Administrator, Sustainable Fisheries Division, Alaska Region, NMFS, Attn: Ellen Sebastian. You may submit comments, identified for this action by 0648–AX71 (NOA), by any one of the following methods:

- Electronic Submissions: Submit all electronic public comments via the Federal eRulemaking Portal *http://www.regulations.gov*.
- Mail: P.O. Box 21668, Juneau, AK 99802.
- Hand delivery to the Federal Building: 709 West 9th Street, Room 420A, Juneau, AK.
- Fax: 907–586–7557.

All comments received are a part of the public record and will generally be posted to *http://www.regulations.gov* without change. All Personal Identifying Information (e.g., name, address) voluntarily submitted by the commenter may be publicly accessible. Do not submit Confidential Business Information or otherwise sensitive or protected information.

NMFS will accept anonymous comments (enter N/A in the required fields, if you wish to remain anonymous). Attachments to electronic comments will be accepted in Microsoft Word, Excel, WordPerfect, or Adobe portable document file (pdf) formats only.

Copies of the Arctic FMP, Amendment 29 to the Crab FMP, maps of the action area and essential fish habitat, and the Environmental Assessment/Regulatory Impact Review/Initial Regulatory Flexibility Analysis (EA/RIR/IRFA) for this action may be obtained from the Alaska Region address above or from the Alaska Region website at *http://www.alaskafisheries.noaa.gov*.

FOR FURTHER INFORMATION CONTACT: Melanie Brown, 907–586–7228.

SUPPLEMENTARY INFORMATION: The Magnuson–Stevens Fishery Conservation and Management Act (Magnuson–Stevens Act) requires that the North Pacific Fishery Management Council (Council) submit any FMP or FMP amendment it prepares to NMFS for review and approval, disapproval, or partial approval by the Secretary of Commerce (Secretary). The Magnuson–Stevens Act also requires that NMFS, upon receiving an FMP or FMP amendment, immediately publish a notice in the **Federal Register** that the FMP or FMP amendment is available for public review and comment.

If approved by the Secretary, the Arctic FMP and Amendment 29 to the Crab FMP would establish sustainable management of commercial fishing in the Arctic Management Area and remove management authority within the Arctic Management Area from the Crab FMP. The Arctic FMP would establish a management framework to sustainably manage future commercial fishing in the Arctic Management Area and would initially prohibit commercial fishing until new information regarding Arctic fish resources allows for authorization of a sustainable commercial fishery in the Arctic Management Area. Amendment 29 to the Crab FMP would ensure consistent management of all crab species in the Arctic Management Area under one FMP.

In February 2009, the Council recommended the adoption of the Arctic FMP to implement a management framework that will protect the fish resources of the Arctic Management Area against the potential onset of unregulated commercial fishing by initially prohibiting commercial fishing until sufficient information is available to enable sustainable management of such fishing consistent with the Magnuson–Stevens Act. Global climate change is reducing the extent of sea ice in the Arctic Ocean, providing greater access to Arctic marine resources and increased human activity in this sensitive marine environment of the U.S. EEZ.

Under the Magnuson–Stevens Act (section 306(a)(3)), the State of Alaska may regulate commercial fishing in the adjacent EEZ waters if no FMP is in place. No FMP is in place for the Arctic Management Area. However, the state authority for management in the EEZ pertains only to vessels registered under the law of the State of Alaska. Thus, absent an FMP it is possible that unregistered vessels could commercially fish in the Arctic Management Area without any regulatory oversight or management. In light of the potential adverse effects on the Arctic marine environment from unregulated commercial fishing, the Council chose to prevent this from occurring in the future. The proposed Arctic FMP would eliminate the potential for unregulated commercial fishing in the Arctic Management Area. The proposed Arctic FMP represents a precautionary, ecosystem–based approach to fisheries management in the Arctic Management Area.

Features of the Arctic FMP

The proposed Arctic FMP contains all required provisions and appropriate discretionary provisions for an FMP contained in sections 303(a), 303(b), and 313 of the Magnuson–Stevens Act. The conservation and management provisions in the Arctic FMP were developed to be consistent with the National Standard guidelines. The following is a summary of the main provisions of the proposed Arctic FMP.

With the exception of Pacific halibut and Pacific salmon, the Arctic FMP would apply to commercial harvests of all fish resources in the waters of the Arctic Management Area (See Figure 1). The geographic extent of the Arctic Management Area would be all marine waters in the U.S. EEZ of the Chukchi and Beaufort Seas, from 3 nautical miles off the coast of Alaska or its baseline to 200 nautical miles offshore, north of Bering Strait (from Cape Prince of Wales to Cape Dezhneva) and westward to the 1990 U.S./Russia maritime boundary line and eastward to the U.S./Canada maritime boundary.

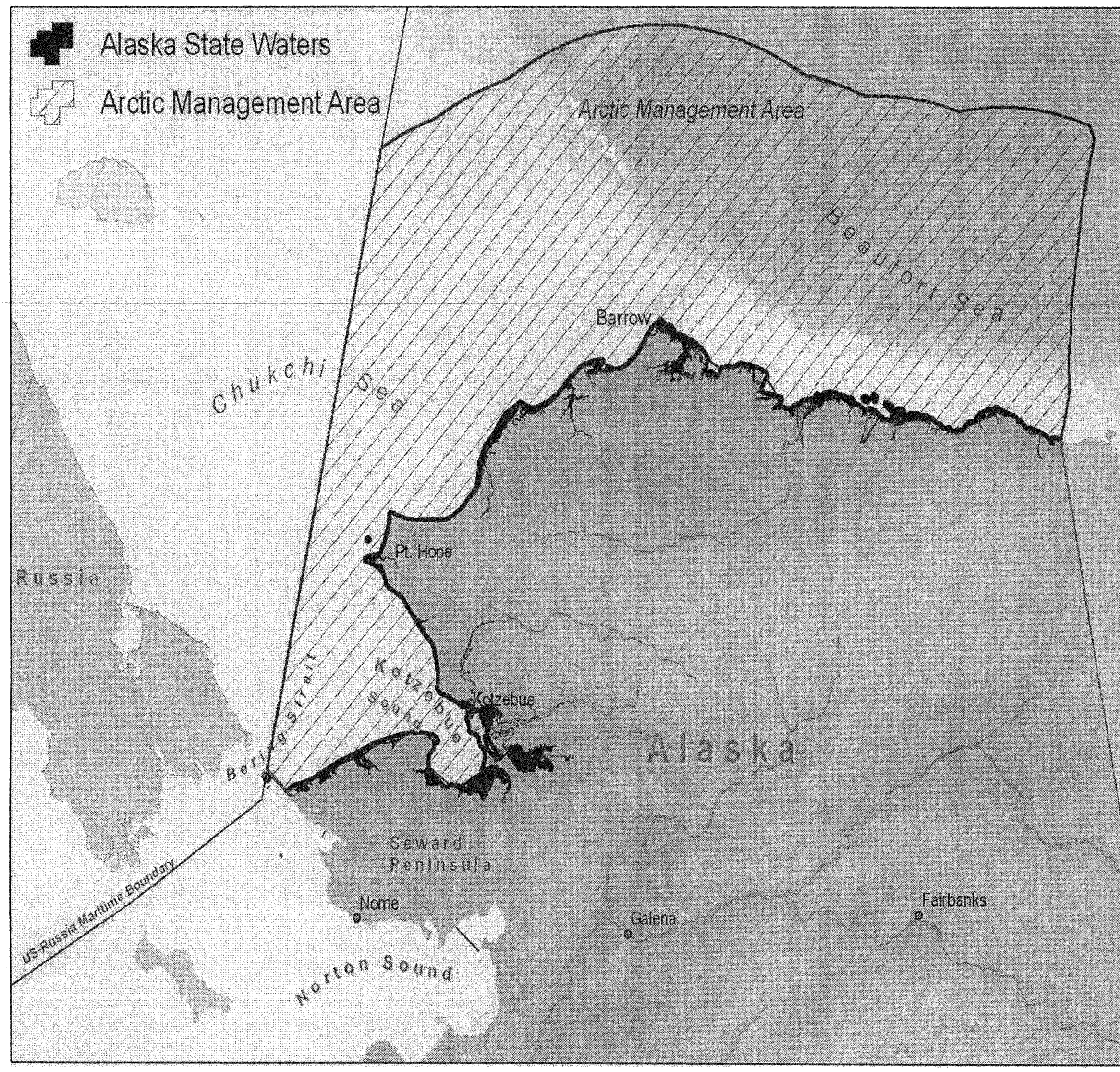

Figure 1. The Proposed Arctic Management Area

This action would not affect non–commercial fishing in the Arctic Management Area, nor commercial harvest of certain species that are managed pursuant to other legal authorities. This action would have no effect on subsistence harvest of marine resources in the Arctic Management Area. It would also have no effect on the commercial harvests of Pacific salmon or Pacific halibut. The commercial harvest of Pacific salmon in the Arctic Management Area is managed under the FMP for Salmon Fisheries in the EEZ off the Coast of Alaska, which prohibits commercial salmon fishing in the Arctic Management Area. Pacific halibut commercial fishing is managed by the International Pacific Halibut Commission, which does not permit harvest of Pacific halibut in the Arctic Management Area.

The proposed Arctic FMP establishes two categories of species, target species and ecosystem component species. Target species are those that are most likely to be targeted in a commercial fishery based on potential markets and available biomass in the Arctic Management Area. Arctic cod (*Boreogadus saida*), saffron cod (*Eleginus gracilis*), and snow crab (*Chionoecetes opilio*) are target species in the proposed Arctic FMP. The remainder of fish, as defined by Section 3 of the Magnuson–Stevens Act, occurring in the Arctic Management Area are classified as ecosystem component species.

The proposed Arctic FMP provides the maximum sustainable yield (MSY) and optimum yield (OY) for commercial fishing for each of the target species. MSY is specified for each target species using the MSY control rule described in the proposed Arctic FMP. The OY for each target species is determined by reductions from MSY based on uncertainty, economic considerations, and ecosystem considerations. The MSYs for Arctic cod, saffron cod, and snow crab would be reduced by 100 percent based on economic costs of fishing. Uncertainty would reduce the

MSY for each target species by an amount ranging from 36 to 61 percent. MSYs for Arctic cod and saffron cod also would be reduced based on ecosystem considerations. Arctic cod is a keystone species in the Arctic marine environment, with many higher trophic level predators (i.e., certain marine mammals and seabirds) heavily dependent on Arctic cod as a principal prey species. The harvest of saffron cod likely would result in very high levels of Arctic cod bycatch (two tons of Arctic cod for each ton of saffron cod); therefore, the harvest of saffron cod also likely would result in impacts on Arctic cod and those species that depend on Arctic cod as prey. Because of the importance of Arctic cod to the Arctic food web, the lack of knowledge of the Arctic cod biomass needed to support both commercial fishing and Arctic predators, and the potential high levels of bycatch of Arctic cod in a saffron cod fishery, the MSYs for Arctic and saffron cods are reduced 100 percent based on ecosystem concerns.

Based on these reductions of the MSYs for the target species, the OY for commercial fishing in the Arctic Management Area for each target species is zero. The proposed Arctic FMP specifies the OY for each target species as the lowest amount of catch sufficient to allow for bycatch of Arctic cod, saffron cod, and snow crab in subsistence fisheries for other species. The Arctic FMP would thus prohibit commercial fishing on target species. With an OY of zero for each target species, no quantity of target species is available for commercial harvest.

The commercial harvest of ecosystem component species also would be prohibited to prevent the adverse effects on the Arctic marine ecosystem, including the target species, that may occur from unregulated commercial fishing on these species. Consistent with the Council's stated management policy and objectives, the proposed Arctic FMP includes non–target species in the ecosystem component category to ensure that the Arctic marine ecosystem is adequately protected and out of concern that unregulated commercial fishing for these species could detrimentally affect the target fishery. The inclusion of all non–target species in the Arctic Management Area in the ecosystem component category is consistent with the Magnuson–Stevens Act which: recognizes the increased importance of habitat conservation; calls for development of conservation and management measures to avoid irreversible or long–term adverse effects to the marine environment and to minimize bycatch to the extent practicable; permits inclusion in an FMP of management measures to conserve non–target species and habitats, considering the variety of ecological factors affecting fishery populations; and requires consideration of ecological factors and protection of the marine ecosystem in setting OY for stocks in the fishery. The National Standard 1 guidelines (50 CFR 600.310(d)(5)(i)) further encourage an ecosystem–based approach to management of fisheries, providing the Council and NMFS with broad discretion to determine whether stocks should be classified and included in an FMP as ecosystem component species for a series of reasons, including specifying OY and developing conservation and management measures for the associated fishery to address other ecosystem issues and to protect their associated role in the ecosystem with which the fishery interacts. Due to the lack of commercial fishing in the Arctic, these species are non–target species and are not generally retained for sale or for personal use. Moreover, these species are not likely to be overfished or be subject to overfishing in the absence of commercial fishing or conservation and management measures.

The Council's decision to create an ecosystem component category that includes all fish species in the Arctic Management Area, except the potential target species, and to prohibit commercial fishing for such species other than salmon and halibut, is based on ecosystem considerations and is intended to conserve target and non–target species and their habitats. The stated management objectives of the Arctic FMP provide a benchmark for NMFS' evaluation of the Council's proposed management measures. These objectives include a ''Biological Conservation Objective'' that seeks to ensure the long–term viability of fish populations by, among other things, preventing unregulated fishing and ''incorporating ecosystem–based considerations into fishery management decisions, as appropriate . . . .'' NMFS believes that the prohibition on commercial fishing for ecosystem component species reflects such appropriate ecosystem–based considerations and does not constitute required conservation and management for purposes of including such species in the fishery.

The OY for each of the three potential target fisheries is de minimis, and sufficient only to support subsistence fishing. NMFS shares the Council's concern that if the target species are caught as bycatch during unregulated commercial fishing for other species, removal of those target species could surpass OY. Similarly, NMFS shares the Council's concern that unregulated commercial fishing for ecosystem component species may affect the Arctic marine ecosystem in ways that are detrimental to the potential target fishery as well as non–target species and their habitats. For example, large–scale removal of biomass of important prey species for one or more target species, or removal of species that are otherwise ecologically connected to one or more target species, could adversely affect the target fishery populations. At present, the scientific understanding of the interdependence and trophic relationships between particular species in the Arctic marine ecosystem is rudimentary, relative to other marine ecosystems, as is the knowledge of particular habitats in the region that may be important to the continued health of the ecosystem and its various species. In particular, NMFS is concerned about the potential adverse effects of unregulated commercial fishing for non–target species on Arctic cod, which is found throughout the Arctic Management Area and is a keystone species that provides a crucial trophic link between the sea ice food web and marine mammals and birds.

These limitations on NMFS' understanding of ecological processes in the Arctic are compounded by the ongoing climatic changes in the region and physical changes in the marine environment. Global climate change is anticipated to continue altering the Arctic environment in fundamental ways, and before long may lead to a seasonally ice–free Arctic Ocean. As a result, there is great uncertainty regarding the ways in which current ecological relationships may change, irrespective of fishing pressure. Consistent with the Council's ecosystem–based management policy, NMFS believes it is appropriate to adopt management measures that will maximize the resilience of the target species and afford the greatest protection to the integrity of the Arctic ecosystem in the face of a changing climate. The prohibition on commercial fishing for ecosystem component species represents such a management measure.

Although there is uncertainty as to whether commercial fishing for ecosystem component species would diminish target fishery populations to an unacceptable degree, either due to bycatch of target species or impacts on the ecosystem, NMFS has determined that the Council appropriately adopted a precautionary approach that proposes prohibiting commercial fishing for any species of Arctic fish in the Arctic Management Area. Given the limited knowledge of ecological relationships and considerable uncertainty regarding the future, this will ensure that fishing does not interfere with important ecological relationships in the Arctic marine environment and thereby avoids the risk of harm to the potential target species, the broader ecosystem, and the habitat of fish species that may otherwise result from unregulated commercial fishing for ecosystem component species. Prohibiting commercial fishing on ecosystem component species is therefore an ecosystem–based, precautionary approach to fish resources management in the Arctic Management Area. NMFS will from time-to-time review the status of ecosystem component species based on the best available scientific information to determine whether or not such species should be classified for active conservation and management as species or stocks in the fishery.

The proposed Arctic FMP includes a process and criteria for evaluating a future commercial fishery. The evaluation process includes the Council's review of an analysis of the biological information on the potential target species and potential impacts of commercial fishing on the Arctic marine environment and on communities. An FMP amendment would be required to authorize a commercial fishery in the Arctic Management Area and to implement the specific conservation and management measures for the fishery.

If a commercial fishery is authorized in the Arctic Management Area, the proposed Arctic FMP provides the general conservation and management measures to ensure sustainable fishing and to prevent overfishing of any target species. Overfishing levels (OFL) and acceptable biological catch levels (ABC) would be established, according to tier systems, based on the quantity of information available. The process for specifying OFLs, ABCs, and total allowable catch amounts (TACs) includes the development of a Stock Assessment and Fishery Evaluation report for the Council's consideration in recommending OFLs, ABCs, and TACs to the Secretary.

The National Standard 1 guidelines (74 FR 3178, January 16, 2009) require accountability measures and mechanisms to prevent overfishing. This requirement would be satisfied by the catch and retention restrictions implemented with the prohibition of commercial fishing initially imposed by the proposed Arctic FMP. If a commercial fishery is authorized in the future, the FMP would be amended to incorporate specific accountability measures and mechanisms to prevent overfishing.

The proposed Arctic FMP includes the process and criteria for issuing exempted fishing permits (EFP). EFPs provide exemptions to fishing regulations under 50 CFR part 679 to allow commercial fishing in a manner not otherwise authorized. These permits are granted for the purpose of allowing studies that provide information useful to the management of fisheries and are effective for a limited time. More information regarding EFPs is available from the NMFS Alaska Region website at *http://www.alaskafisheries.noaa.gov/ram/efp.htm*.

Essential fish habitat (EFH) is described for each target species in the proposed Arctic FMP. Once EFH is established, NMFS must be consulted for any federal action that may adversely impact EFH (Magnuson–Stevens Act section 305(b)(2)). The proposed EFH description for Arctic cod includes the entire Arctic Management Area. Proposed EFH locations for snow crab and saffron cod are primarily in the Chukchi Sea. Descriptions of potential non–fishing adverse impacts on EFH and mitigation are appended to the proposed Arctic FMP.

To assist in the ecosystem approach to fisheries management, the proposed Arctic FMP includes habitat descriptions for several ecosystem component species. The species selected for habitat descriptions represent forage species and potential future target species based on Bering Sea commercial fishing.

The proposed Arctic FMP also includes the latest information on the Arctic ecosystem and Chukchi and Beaufort Seas survey data. This information provides the basis for the MSY and OY specifications and informed the Council's decision to recommend adoption of the Arctic FMP.

Amendment 29 to the Crab FMP

Amendment 29 to the Crab FMP would move the northern boundary of the Crab FMP management area to Bering Strait. The Crab FMP northern boundary is currently located at Point Hope, north of Bering Strait and within the Arctic Management Area (See Figure 1). This change in the Crab FMP northern boundary would allow the management of all crab species in the Arctic Management Area to be under the Arctic FMP, and would ensure consistent application of the conservation and management measures in the Arctic FMP to crab throughout the Arctic Management Area. The Arctic FMP's conservation and management measures were designed to address the unique Arctic marine environment and the paucity of information available for sustainable fisheries management. Because the information available for Arctic crab and the marine environment of the Arctic Management Area differs from the Bering Sea, the Council recommended management of crab in the Arctic Management Area under the Arctic FMP.

Public Comments

NMFS is soliciting public comments on the proposed Arctic FMP and Crab FMP amendment through July 27, 2009. A proposed rule that would implement the Arctic FMP and Crab FMP amendment will be published in the **Federal Register** for public comment at a later date, following NMFS' evaluation pursuant to the Magnuson–Stevens Act. Public comments on the proposed rule must be received by the end of the comment period on the Arctic FMP and Crab FMP amendment in order to be considered in the approval/disapproval decision on the Arctic FMP and Crab FMP amendment. All comments received on the Arctic FMP and Crab FMP amendment by the end of the comment period, whether specifically directed to the FMP or amendment or to the proposed rule, will be considered in the approval/disapproval decision. Comments received after that date will not be considered in the approval/disapproval decision on the Arctic FMP or Crab FMP amendment. To be considered, comments must be received— not just postmarked or otherwise transmitted—by 1700 hours, A.D.T. on the last day of the comment period (See **DATES** and **ADDRESSES**).

Authority: 16 U.S.C. 1801 *et seq.*

Dated: May 20, 2009.

Margo Schulze–Haugen,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. E9–12151 Filed 5–22–09; 8:45 am]

BILLING CODE 3510–22–S

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Parts 679 and 680

[Docket No. 080312430–8503–01]

RIN 0648–AW56

Fisheries of the Exclusive Economic Zone Off Alaska; Western Alaska Community Development Quota Program, Rockfish Program, Amendment 80 Program; Bering Sea and Aleutian Islands Area Crab Rationalization Program

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

ACTION: Proposed rule; request for comments.

SUMMARY: NMFS proposes regulations to provide harvesting cooperatives, crab processing quota share holders, and Western Alaska Community Development Quota (CDQ) groups with the option to make intercooperative transfers, crab individual processing quota transfers, and inter-group transfers through an automated, web-based process. To facilitate web-based transfers, NMFS would remove the requirement for notarized signatures for all crab non-permanent leases of individual fishing quota and individual processor quota and remove unnecessary quota share price-related questions. The purpose of this action is to reduce paperwork burdens placed on the fishing industry by providing the option of electronic transfer through the Internet. This action would allow cooperatives, processors, and CDQ groups to shorten response time to management, market, weather, and other fishery and operational conditions and to increase harvesting and processing efficiency. This action also proposes a variety of ''housekeeping'' but necessary regulatory amendments including: removing detailed description of applications from regulatory text; removing detailed NMFS mail, fax, and delivery addresses and replacing them with one paragraph stating that the form may be submitted in accordance with instructions on the form; removing outdated survey-type questions from two applications; dividing one application into three separate applications; revising the NMFS Alaska Region web address; and correcting cross-references.

DATES: Comments must be received no later than June 10, 2009.

ADDRESSES: You may submit comments, identified by 0648–AW56, by any one of the following methods:

- Electronic Submissions: Submit all electronic public comments via the Federal eRulemaking Portal *http://www.regulations.gov.*
- Fax: 907–586–7557
- Mail: P.O. Box 21668, Juneau, AK 99802.
- Hand delivery to the Federal Building: 709 West 9th Street, Room 420A, Juneau, AK.

All comments received are a part of the public record and will generally be posted to *http://www.regulations.gov* without change. All Personal Identifying Information (for example, name, address, etc.) voluntarily submitted by the commenter may be publicly accessible. Do not submit Confidential Business Information or otherwise sensitive or protected information.

NMFS will accept anonymous comments (enter N/A in the required fields, if you wish to remain anonymous). You may submit attachments to electronic comments in Microsoft Word, Excel, WordPerfect, or Adobe PDF file formats only.

Copies of the Categorical Exclusion (CE), Regulatory Impact Review (RIR), and Initial Regulatory Flexibility Analysis (IRFA) prepared for this action may be obtained from the NMFS Alaska Region, P.O. Box 21668, Juneau, Alaska 99802, Attn: Ellen Sebastian, and on the NMFS Alaska Region website at *http://alaskafisheries.noaa.gov.*

Written comments regarding the burden-hour estimates or other aspects of the collection-of-information requirements contained in this rule may be submitted to NMFS at the above address, and by e-mail to *David_Rostker@omb.eop.gov* or by fax to 202–395–7285.

FOR FURTHER INFORMATION CONTACT: Patsy A. Bearden, 907–586–7008.

SUPPLEMENTARY INFORMATION: NMFS manages the U.S. groundfish fisheries of the Bering Sea and Aleutian Islands in the Exclusive Economic Zone under the Fishery Management Plan for Groundfish of the Bering Sea and Aleutian Islands Management Area (BSAI FMP) and the Fishery Management Plan for Groundfish of the Gulf of Alaska (GOA FMP). The crab fisheries are managed under the Fishery Management Plan for Bering Sea and Aleutian Islands King and Tanner Crabs (Crab FMP). The BSAI FMP, GOA FMP, and Crab FMP were prepared by the North Pacific Fishery Management Council (Council) under the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act). Regulations implementing the FMPs appear at 50 CFR part 679 and part 680. General regulations that pertain to U.S. fisheries appear at subpart H of 50 CFR part 600.

Background

The Council has adopted and NMFS has implemented five management programs that allocate quota share and associated harvesting or processing privileges to qualified entities and allow for the transfer of these privileges among qualified entities upon approval by NMFS. The provision for electronic online quota transfers is proposed for four of these programs—the Western Alaska Community Development Quota Program (CDQ Program), the Central GOA Rockfish Pilot Program (Rockfish Program), Amendment 80 to the Fishery Management Plan for Groundfish of the Bering Sea and Aleutian Islands Management Area (Amendment 80 Program), and in the Bering Sea and Aleutian Islands Area Crab Rationalization (CR) Program. Each of these programs authorizes transfers of quota shares under particular circumstances. Depending on the circumstances, the transfers—which are typically leasing arrangements—are between individuals, cooperatives, or various commercial entities. The fifth quota share program, Halibut and Sablefish IFQ, is not proposed to be included in online transfers. There are minimal leasing opportunities for this program that are conditioned upon submission of documentation that can only be provided in paper form, such as medical records.

Need for Action

Currently, applications for transfers must be submitted to NMFS by mail, courier, or fax. The current hard-copy application transfer process is too slow to meet operational and market demands of fishery participants. The efficacy of current system of transfers is limited by NMFS business hours; requirements for original application documents and notarized signatures; and the lengths of time needed for application submission, approval, and receipt of permits.

This action would offer an additional electronic option for applicants to accomplish certain transfers through automated, online submittals and automated transfer processing. Electronic transfer service also would benefit NMFS as it would reduce existing transfer processing labor needs, improve data quality, and promote the objectives of the Government Paperwork Elimination Act.

This rule standardizes the regulatory text that the individuals providing information certify that the information provided is ''true, correct, and complete to the best of his or her knowledge and belief.'' In paragraph 679.5(n)(1), this text is added for the CDQ Program. Paragraph 679.81(f)(2) is revised for the Rockfish Program. Paragraph 679.91(g) is revised for the Amendment 80 Program. Paragraphs 680.21(f) and 680.41(h) are revised for the CR Program.

With respect to quota transfers, this action would not change any eligibility requirements, schedules, or any part of the programs involved other than to provide a web-based option to submit applications and conduct transfers online. The transfer regulations for each program would be amended to specify that both paper and online applicants certify information supporting the transfers. Particular amendments for each program would be as follows:

Section 679.5(n) Groundfish CDQ Fisheries

Paragraph (n) of § 679.5 details the recordkeeping and reporting (R&R) requirements for groundfish CDQ fisheries, including CDQ and PSQ transfers. In addition to adding an online transfer process, paragraph (n)(1) would be revised by removing the detailed description of transfer applications, because that detail is provided on the application and in the instructions.

Section 679.81 Rockfish Program Annual Harvester and Processor Privileges

Section 679.81(e) describes the applications for the Rockfish Program. Paragraph (e) would be amended to establish the application for the online transfers. Paragraph (e)(1) would be amended to update application mailing and website addresses.

Section 679.81(f) describes the ''Application for Inter-Cooperative Transfer of Rockfish Cooperative Quota (CQ).'' Paragraph (f) would be revised by removing duplicative and unnecessary description of the transfer request, because the information is provided on the application and in the instructions.

Section 679.91 Amendment 80 Program Annual Harvester Privileges

Section 679.91 describes requirements for the Amendment 80 Program annual harvester privileges and transfer processes. An online transfer process would be added and application mailing and website addresses would be updated.

NMFS would amend the regulatory text to enhance its accuracy and usefulness. Paragraph (g) would be revised to read ''Application for Inter-Cooperative Transfer of Amendment 80 Cooperative Quota (CQ)'' because this is the only application described in this section. Paragraph (g) would be revised to remove detailed description of the application and other information that may be found on the form and in the instructions. Paragraph (g)(1), a general description of the transfer request, would be added. Paragraphs (g)(4)(iv) through (vi) would be redesignated as paragraphs (g)(2) through (4), respectively.

Section 680.41 Transfer of QS, PQS, IFQ and IPQ

The proposed rule would provide for online transfers and add the Alaska Region website address and location of forms. NMFS also proposes to remove duplicative text regarding each of the quota transfer applications. As this change would eliminate text, the proposed rule would redesignate paragraphs accordingly. The section describing notification of approval by the Regional Administrator would be revised by simplifying the language and removing the text specifying that the applicants would be notified of a successful transfer or denial of a transfer by mail because NMFS would have more than one method of notifying applicants.

Paragraph (h) describes transfer of crab QS/IFQ or PQS/IPQ all in one application. NMFS proposes to divide-up the unified application. The proposed rule would reorganize and revise paragraph (h) to separate the single application into three applications and revise the heading for paragraph (h). Using one form to request information for three different permits with different information requirements is overly complicated and confusing. In view of the proposed changes, the heading for paragraph 680.41(h) would be revised to accurately describe this section.

The regulations governing QS/PQS transfers would be revised to allow submittal of legible faxes. Cooperative transfers and transfers of IFQ or IPQ would be revised to remove requirements for notary and price data and to allow submittal of legible faxes.

In addition, six ''survey type'' questions asking for background information would be removed from applications for cooperative transfers and transfers of IFQ or IPQ. These questions seek costs associated with transfers, prices paid for leasing, and reasons for the transfer. These are temporary annual transfers. NMFS has determined that the information on reasons for transfers is not helpful or informative for management goals. Data on permanent quota share transfers are more significant socio-economic information and NMFS will continue to seek this information.

Paragraphs (h)(1) through (h)(3) would be revised by removing the detailed description of the electronic and paper transfer request, because that detail is provided on the form and in the instructions to the form.

Other Regulatory Amendments

Section 680.5 Recordkeeping and reporting (R&R). Section 680.5 describes recordkeeping and reporting requirements for the CR Program. As one of two housekeeping measures, a cross-reference to the CR crab landing report would be corrected.

The proposed rule would revise paragraph (g) by removing the descriptions of various methods and addresses for submittal of the RCR fee submission form and by replacing it with text instructing the participants to refer to the fee form submittal instructions on the NMFS Alaska Region website at *http://alaskafisheries.noaa.gov*. This would simplify and shorten regulatory text.

Section 680.20 Arbitration System. Section 680.20 describes the CR Program Arbitration System and requirements to submit arbitration reports and other arbitration information to NMFS and related submittal deadlines. The proposed rule would standardize submittal addresses for the CR Program Arbitration System by placing the complete mailing address for NMFS into paragraph 680.20(a)(3), by removing NMFS address information from paragraphs (d)(3), (d)(4), (e)(5), (f)(4)(ii)(B), (g)(2)(viii)(C)(*2*), and (h)(6) introductory text, and by adding a cross-reference to paragraph (a)(3) to identify what information must be submitted and by whom.

Section 680.21 Crab Harvesting Cooperatives. Section 680.21 contains provisions for CR Program harvesting cooperatives, including transfer requirements. The heading for paragraph (f) would be revised to read ''Application for Transfer of Crab Harvesting Cooperative IFQ'' to correct the name of the application. NMFS would change the format of paragraph (f) by removing detailed descriptions of the transfer application and replacing that text with information stating that a complete and timely application must be filed with NMFS and that instructions are provided on the form. NMFS believes that all participants have access to and knowledge of the applications on the Alaska Region website.

Section 680.40 Crab QS, PQS, IFQ, IPQ Issuance. The section heading and paragraph heading would be amended to clarify the topic descriptions. The proposed rule would modify the various methods and addresses for submittal, so that applicants would be directed to the Alaska Region website address for forms and instructions.

Section 680.44 Cost Recovery. Paragraph (a)(4)(iii) would be revised by removing the detailed submittal addresses for mail, fax, and courier delivery and replacing them with a paragraph stating that the form may be submitted in accordance with instructions on the form.

The proposed rule would revise the NMFS Alaska Region web address to *http://alaskafisheries.noaa.gov* for all information submitted electronically and for all other uses, including access to application forms and program information in the 50 CFR part 679 and in the 50 CFR part 680 regulations.

Classification

Pursuant to section 305(d) of the Magnuson-Stevens Act, the NMFS Acting Assistant Administrator has determined that this proposed rule is consistent with the provisions of the Magnuson-Stevens Act and other applicable law, subject to further consideration after public comment.

NMFS prepared an initial regulatory flexibility analysis (IRFA), as required by section 603 of the Regulatory Flexibility Act (RFA). The IRFA describes the economic impact this proposed rule, if adopted, would have on small entities. Descriptions of the action, the reasons it is under consideration, and its objectives and legal basis, are contained at the beginning of this section in the preamble and in the **SUMMARY** section of the preamble. A summary of the analysis follows. A copy of this analysis is available from NMFS (see **ADDRESSES**).

The IRFA for this proposed action describes in detail the reasons why this action is being proposed; describes the objectives and legal basis for the proposed rule; describes and estimates the number of small entities to which the proposed rule would apply; describes any projected reporting, recordkeeping, or other compliance requirements of the proposed rule; identifies any overlapping, duplicative, or conflicting Federal rules; and describes any significant alternatives to the proposed rule that accomplish the stated objectives of the Magnuson-Stevens Act and any other applicable statutes, and that would minimize any significant adverse economic impact of the proposed rule on small entities.

The description of the proposed action, its purpose, and its legal basis are described in the preamble and are not repeated here.

This action would provide participants in the CDQ Program, Rockfish Program, Amendment 80 Program, and CR Program the opportunity to submit quota transfer applications electronically, with the potential for processing and approving quota transfers electronically, entirely over the Internet. Program participants have commented that current transfer processes are not flexible or responsive enough to meet the needs of a 24-hour, seven-days-a-week, short-term fishery that must continually reorganize allocations to meet operational and market demands. For example, cooperatives frequently use inter-cooperative leases to maximize the efficient use of vessels and allocations. The proposed electronic processes would address the problems of limited business hours of NMFS staff; requirements for original application documents and notarized signatures; and the lengths of time needed for application submission, approval, and receipt of permits. The proposed revisions would benefit Program participants by reducing the time, expense, and administrative effort associated with submitting requests to NMFS for approval of quota transfers.

This action would impact administrative procedures for fisheries management programs within the Alaska Region. This rule creates a new option for CDQ groups, Rockfish Cooperatives, the Amendment 80 cooperatives, the Crab Harvesting cooperatives, and crab IPQ holders to transfer annual allocations of CDQ, CQ, IFQ, or IPQ (as appropriate) among themselves online to make transfers more efficient and faster. Prior to this action these entities submitted transfer paperwork to NMFS using only the mail, fax, and/or courier.

These changes would create no new costs for industry, because the costs of implementation have already been incurred. In fact, the industry may have fewer costs. NMFS expects that the participants of those programs will tend to participate in online activities because the option is expected to reduce their reporting requirements, increase operational flexibility, enhance potential for collaboration and coordination among transferors and transferees, and provide an augmented ability to respond in a timely way to operational logistics and market changes. Transfer participants will not have to wait for NMFS to approve and complete the transfer and notify them on completion. They can conduct such transfers when it is convenient for them to do so—evenings, weekends, holidays and other non-business hours.

This change would create no new costs for NMFS, because the costs of implementation have already been incurred. To the extent that industry uses this option, administrative costs for NMFS would also be reduced by streamlining the administrative process, with no appreciable loss of necessary data or management capabilities. Automated checks in the submission system will monitor applications for completeness and consistency with law. Paper applications would only be required if problems occurred with the electronic transfer attempt or in some situations requiring attachments that must be examined by NMFS staff.

This action also would divide the single form currently used to apply for transfers of crab QS/IFQ or PQS/IPQ into three separate forms governing transfers of crab IFQ, crab IPQ, and crab QS or PQS. Currently somewhat different information is collected for each type of transfer, but only one form is used for the applications. This form is therefore unnecessarily complicated.

NMFS estimates that this action may directly regulate six small CDQ groups, one small rockfish cooperative, no small Amendment 80 cooperatives, four small crab cooperatives, 18 small crab PQS holders, 31 small crab IFQ holders, 13 small crab IPQ holders, 250 small crab QS holders, and 25 small crab PQS holders.

The IRFA did not reveal any Federal rules that duplicate, overlap, or conflict with the proposed action.

The alternatives were developed to minimize potential adverse economic effects on directly regulated entities. The objectives of this action are to:

♦ Maintain recordkeeping and reporting requirements for the impacted programs that provide the information necessary to manage the fisheries and to enforce Federal regulations applicable to the programs.

♦ Reduce the time, effort, and documentation involved in the process of making quota transfers.

♦ Maintain the overall economic and social goals and purpose of the regulated programs.

NMFS initially considered an alternative that would have required use of the online systems rather than making them optional. NMFS rejected this alternative without analysis because NMFS could not be certain that all entities in all impacted industry sectors had the capability of submitting forms electronically and because some transfers still require attachments that must be examined by NMFS staff. The preferred alternative reflects the least burdensome of management structures in terms of directly regulated small entities available, while fully achieving the conservation and management purposes consistent with applicable statutes.

This proposed rule has been determined to be not significant for purposes of Executive Order 12866.

This regulation does not impose new recordkeeping and reporting requirements on the regulated small entities.

Collection-of-Information Requirements

This rule contains collection-of-information requirements subject to the Paperwork Reduction Act (PRA) and which have been approved by the Office of Management and Budget (OMB). Public reporting burden estimates per response for these requirements are listed by OMB control number.

OMB Control No. 0648–0269: 30 minutes for CDQ or PSQ Transfer Request.

OMB Control No. 0648–0565: Two hours for Application to Transfer Amendment 80 Cooperative Quota.

OMB Control No. 0648–0545: Two hours for Application for Inter-cooperative Transfer of Rockfish Quota Share.

This proposed rule contains collection-of-information requirements subject to review and approval by OMB under the PRA and which have been submitted to OMB for approval. Public reporting burden estimates per response for these requirements are listed by OMB control number.

OMB Control No. 0648–0514: Two hours for Application for Transfer of Crab QS, IFQ, and IPQ; this form will be removed from this collection, and the following three new forms will be added in its place. Two hours each for: Application for Transfer of Crab Individual Fishing Quota, Application for Transfer of Individual Processor Quota, Application for Transfer of Crab Quota Share and Crab Processor Quota Share, and Application for Transfer of Individual Fishing Quota Between Crab Harvesting Cooperatives; and two and one half hours for Application for Annual Crab Harvester Cooperative IFQ Permit.

Public reporting estimates include the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection-of-information.

Public comment is sought regarding whether these proposed collections-of-information are necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; the accuracy of the burden estimate; ways to enhance the quality, utility, and clarity of the information to be collected; and ways to minimize the burden of the collection-of-information, including through the use of automated collection techniques or other forms of information technology.

Send comments on these or any other aspects of the collection-of-information to NMFS Alaska Region at the ADDRESSES above, and e-mail to *David_Rostker@omb.eop.gov,* or fax to 202–395–7285.

Notwithstanding any other provision of the law, no person is required to respond to, nor shall any person be subject to a penalty for failure to comply with, a collection-of-information subject to the requirements of the PRA, unless that collection-of-information displays a currently valid OMB Control Number.

List of Subjects in 50 CFR Parts 679 and 680

Alaska, Fisheries, Recordkeeping and reporting requirements.

Dated: May 18, 2009.

John Oliver,

Deputy Assistant Administrator for Operations, National Marine Fisheries Service.

For the reasons set out in the preamble, 50 CFR parts 679 and 680 are proposed to be amended as follows:

PART 679—FISHERIES OF THE EXCLUSIVE ECONOMIC ZONE OFF ALASKA

1. The authority citation for part 679 continues to read as follows:

Authority: 16 U.S.C. 773 *et seq.;* 1801 *et seq.;* 3631 *et seq.;* Pub. L. 108–447.

2. In § 679.5, revise paragraph (n)(1) to read as follows:

§ 679.5 Recordkeeping and reporting (R&R).

* * * * *

(n) * * *

(1) *CDQ or PSQ transfer.* NMFS will process a request for CDQ or PSQ transfer between CDQ groups provided that the requirements of this paragraph are met.

(i) *Completed application.* A paper or electronic request form must be completed with all information fields accurately filled in by transferors and transferees, and all required additional documentation must be attached.

(ii) *Transfer acceptance.* In the case of an online transfer, the transferee group must accept the transfer.

(iii) *Certification of transferor*—(A) *Non-electronic submittal.* The transferor's designated representative must sign and date the application certifying that all information is true, correct, and complete.

(B) *Electronic submittal.* The transferor's designated representative must submit the application as indicated on the computer screen. By using the transferor's NMFS ID, password and Transfer Key and submitting the application, the designated representative certifies that all information is true, correct, and complete.

(iv) *Certification of transferee*—(A) *Non-electronic submittal.* The transferee's designated representative must sign and date the application certifying that all information is true, correct, and complete.

(B) *Electronic submittal.* The transferee's designated representative must submit the application as indicated on the computer screen. By using the transferee's NMFS ID, password and Transfer Key and submitting the application, the designated representative certifies that all information is true, correct, and complete.

* * * * *

3. In § 679.81, add paragraph (e)(1)(iv); and revise paragraphs (e)(2) and (f) to read as follows:

§ 679.81 Rockfish Program annual harvester and processor privileges.

* * * * *

(e) * * *

(1) * * *

(iv) *Electronic: http://alaskafisheries.noaa.gov.*

(2) *Application forms.* Application forms are available on the NMFS Alaska Region website at *http://alaskafisheries.noaa.gov*, or by contacting NMFS at 800–304–4846, Option 2.

* * * * *

(f) *Application for inter-cooperative transfer of cooperative quota (CQ)*—(1) *Completed application.* NMFS will process an application for inter-cooperative transfer of cooperative quota (CQ) provided that a paper or electronic online transfer application is completed by the transferor and transferee, with all applicable fields accurately filled-in, and all required additional documentation is attached.

(2) *Certification of transferor*—(i) *Non-electronic submittal.* The transferor's designated representative must sign and date the application

certifying that all information is true, correct, and complete.

(ii) *Electronic submittal.* The transferor's designated representative must submit the application as indicated on the computer screen. By using the transferor's NMFS ID, password and Transfer Key and submitting the application, the designated representative certifies that all information is true, correct, and complete.

(3) *Certification of transferee*—(i) *Non-electronic submittal.* The transferee's designated representative must sign and date the application certifying that all information is true, correct, and complete.

(ii) *Electronic submittal.* The transferee's designated representative must submit the application as indicated on the computer screen. By using the transferee's NMFS ID, password and Transfer Key and submitting the application, the designated representative certifies that all information is true, correct, and complete.

* * * * *

4. In § 679.91, add paragraph (b)(1)(iv); and revise paragraphs (b)(2) and (g) to read as follows:

§ 679.91 Amendment 80 Program annual harvester privileges.

* * * * *

(b) * * *

(1) * * *

(iv) *Electronic: http://alaskafisheries.noaa.gov.*

(2) *Application forms.* Application forms are available on the NMFS Alaska Region website at *http://alaskafisheries.noaa.gov*, or by contacting NMFS at 800–304–4846, Option 2.

* * * * *

(g) *Application for inter-cooperative transfer of Amendment 80 CQ*—(1) *Completed application.* NMFS will process an application for inter-cooperative transfer of Amendment 80 cooperative quota (CQ) provided that a paper or electronic application is completed by the transferor and transferee, with all applicable fields accurately filled in, and all required additional documentation is attached.

(2) *Amendment 80 species CQ assignment.* Amendment 80 species CQ must be assigned to a member of the Amendment 80 cooperative receiving the CQ for purposes of use cap calculations. No member of an Amendment 80 cooperative may exceed the CQ use cap applicable to that member.

(3) *Total amount of Amendment 80 species CQ.* For purposes of Amendment 80 species CQ use cap calculations, the total amount of Amendment 80 species CQ held or used by a person is equal to all metric tons of Amendment 80 species CQ derived from all Amendment 80 QS units on all Amendment 80 QS permits held by that person and assigned to the Amendment 80 cooperative and all metric tons of Amendment 80 species CQ assigned to that person by the Amendment 80 cooperative from approved transfers.

(4) *Amendment 80 QS units.* The amount of Amendment 80 QS units held by a person, and CQ derived from those Amendment 80 QS units, is calculated using the individual and collective use cap rule established in § 679.92(a).

(5) *Certification of transferor*—(i) *Non-electronic submittal.* The transferor's designated representative must sign and date the application certifying that all information is true, correct, and complete.

(ii) *Electronic submittal.* The transferor's designated representative must submit the application as indicated on the computer screen. By using the transferor's NMFS ID, password and Transfer Key and submitting the application, the designated representative certifies that all information is true, correct, and complete.

(6) *Certification of transferee*—(i) *Non-electronic submittal.* The transferee's designated representative must sign and date the application certifying that all information is true, correct, and complete.

(ii) *Electronic submittal.* The transferee's designated representative must submit the application as indicated on the computer screen. By using the transferee's NMFS ID, password and Transfer Key and submitting the application, the designated representative certifies that all information is true, correct, and complete.

* * * * *

PART 680—SHELLFISH FISHERIES OF THE EXCLUSIVE ECONOMIC ZONE OFF ALASKA

5. The authority citation for part 680 continues to read as follows:

Authority: 16 U.S.C. 1862; Pub. L. 109–241; Pub. L. 109–479.

6. In § 680.5, revise paragraphs (a)(2)(i)(G), (g)(1), and (g)(2) to read as follows:

§ 680.5 Recordkeeping and reporting (R&R).

(a) * * *

(2) * * *

(i) * * *

Recordkeeping and reporting report	Person responsible	Reference
* * * * * * *		
(G) CR Crab Landing Report	RCR	§ 679.5(e)
* * * * * * *		

* * * * *

(g) * * *

(1) *Applicability.* An RCR or the RCR's authorized representative, who receives any CR crab pursuant to § 680.44 must submit to NMFS online a complete RCR fee form as instructed on the form at NMFS Alaska Region website at *http://alaskafisheries.noaa.gov*.

(2) *Due date and submittal.* The reporting period of the RCR fee submission shall be the crab fishing year. An RCR must submit any crab cost recovery fee liability payment(s) and the RCR fee submission form to NMFS online not later than July 31 following the crab fishing year in which the CR crab landings were made.

* * * * *

7. In § 680.20, add paragraph (a)(3); and revise paragraphs (d)(3), (d)(4), (e)(5), (f)(4)(ii)(B), (g)(2)(viii)(C)(*2*), and (h)(6) introductory text to read as follows:

§ 680.20 Arbitration System.

(a) * * *

(3) *Document submittal information.* Submit documents and reports to NMFS as follows: by mail to the Regional Administrator, NMFS, P.O. Box 21668, Juneau, AK 99802; by courier to NMFS, Room 401, 709 West 9th Street, Juneau, AK 99801; or by fax to 907–586–7465.

* * *

(d) * * *

(3) An Arbitration Organization, with members who are QS or PQS holders, must submit a complete Annual Arbitration Organization Report to NMFS in accordance with paragraph (a)(3) of this section by August 20, 2005, for the crab fishing year beginning on July 1, 2005, and by May 1 of each subsequent year for the crab fishing year beginning on July 1 of that year.

(4) An Arbitration Organization, with members who are IFQ or IPQ holders, must submit a complete Annual Arbitration Organization Report to NMFS in accordance with paragraph (a)(3) of this section by not later than 15 days after the issuance of IFQ and IPQ for that crab QS fishery.

(e) * * *

(5) *Notification to NMFS.* Not later than June 1 for that crab fishing year,

except as provided in paragraph (e)(6) of this section, the Arbitration Organizations representing the holders of Arbitration QS and PQS in each fishery shall notify NMFS of the persons selected as the Market Analyst, Formula Arbitrator, and Contract Arbitrator(s) for the fishery in accordance with paragraph (a)(3) of this section.

* * * * *

(f) * * *

(4) * * *

(ii) * * *

(B) NMFS Alaska Region in accordance with paragraph (a)(3) of this section; and

* * * * *

(g) * * *

(2) * * *

(viii) * * *

(C) * * *

(*2*) NMFS in accordance with paragraph (a)(3) of this section; and

* * * * *

(h) * * *

(6) *Information provided to NMFS.* The Contract Arbitrator must provide any information, documents, or data required under this paragraph to NMFS in accordance with paragraph (a)(3) of this section not later than 30 days prior to the end of the crab fishing year for which the open negotiation or arbitration applied. The contract with the Contract Arbitrator must specify that the Contract Arbitrator provide NMFS with:

* * * * *

8. In § 680.21, revise paragraph (f) to read as follows:

§ 680.21 Crab harvesting cooperatives.

* * * * *

(f) *Application for transfer of crab harvesting cooperative IFQ*—(1) *Completed application.* NMFS will process an application for transfer of crab harvesting cooperative individual fishing quota (IFQ) provided that a paper or electronic request form is completed by the applicant, with all applicable fields accurately filled in, and all required additional documentation is attached.

(2) *Certification of transferor*—(i) *Non-electronic submittal.* The transferor's designated representative must sign and date the application certifying that all information is true, correct, and complete.

(ii) *Electronic submittal.* The transferor's designated representative must submit the application as indicated on the computer screen. By using the transferor's NMFS ID, password and Transfer Key and submitting the application, the designated representative certifies that all information is true, correct, and complete.

(3) *Certification of transferee*—(i) *Non-electronic submittal.* The transferee's designated representative must sign and date the application certifying that all information is true, correct, and complete.

(ii) *Electronic submittal.* The transferee's designated representative must submit the application as indicated on the computer screen. By using the transferee's NMFS ID, password and Transfer Key and submitting the application, the designated representative certifies that all information is true, correct, and complete.

(4) *Submittal information.* Submit applications and other documents in this section to NMFS as follows: by mail addressed to the Regional Administrator, NMFS, P.O. Box 21668, Juneau, AK 99802; by courier to NMFS, Room 713, 709 West 9th Street, Juneau, AK 99801; by fax to 907–586–7354; or online at *http://alaskafisheries.noaa.gov*.

(5) *Forms.* Forms are available on the NMFS Alaska Region website at *http://alaskafisheries.noaa.gov*, or by contacting NMFS at 800–304–4846, Option 2.

* * * * *

9. In § 680.40, revise the section heading, paragraph (f) heading, and paragraph (f)(1)(ii) to read as follows:

§ 680.40 Crab Quota Share (QS), Processor QS (PQS), Individual Fishing Quota (IFQ), and Individual Processor Quota (IPQ) Issuance.

* * * * *

(f) Application for crab QS or PQS.

(1) * * *

(ii) An application for crab QS or PQS may be submitted to NMFS as instructed on the application. Forms are available on the NMFS Alaska Region website at *http://alaskafisheries.noaa.gov*, or by contacting NMFS at 800–304–4846, Option 2.

* * * * *

10. In § 680.41, revise paragraphs (b) and (h) to read as follows:

§ 680.41 Transfer of QS, PQS, IFQ and IPQ.

* * * * *

(b) *Transfer applications*—(1) *Application.* An application is required to transfer any amount of QS, PQS, IFQ, or IPQ. A transfer application will not be approved until the necessary eligibility application has been submitted and approved by NMFS in accordance with paragraph (c) of this section. The Regional Administrator will not approve any transfers of QS, PQS, IFQ, or IPQ in any crab QS fishery from August 1 until the date of the issuance of IFQ or IPQ for that crab QS fishery.

(2) *Notification of application approval or disapproval.* Persons submitting any application for approval under § 680.41 will receive notification of the Regional Administrator's decision to approve or disapprove the application, and if applicable, the reason(s) for disapproval.

(3) *Reasons for disapproval.* Reasons for disapproval of an application include, but are not limited to:

(i) Lack of U.S. citizenship, where U.S. citizenship is required;

(ii) Failure to meet minimum requirements for sea time as a member of a harvesting crew;

(iii) An incomplete application, including fees and an EDR, if required;

(iv) An untimely application; or

(v) Fines, civil penalties, or other payments due and owing, or outstanding permit sanctions resulting from Federal fishery violations.

(4) *QS, PQS, IFQ, or IPQ accounts.* (i) QS, PQS, IFQ, or IPQ accounts affected by a transfer approved by the Regional Administrator will change on the date of approval.

(ii) For non-electronic submittals, any necessary IFQ or IPQ permits will be sent with the notification of approval if the receiver of the IFQ or IPQ permit has completed an annual application for crab IFQ or IPQ permit for the current fishing year as required under § 680.4.

(iii) For electronic submittals, the parties to the transfer would access and print approvals and permits online.

(5) *Submittal.* Submit applications and other documents to NMFS as instructed on the application. Forms are available on the NMFS Alaska Region website at *http://alaskafisheries.noaa.gov*, or by contacting NMFS at: 800–304–4846, Option 2.

* * * * *

(h) *Applications for transfer*—(1) *Application for transfer of crab IFQ.* NMFS will process a request for transfer of crab individual fishing quota (IFQ) provided that a paper application is completed, with all information fields accurately filled in, and all required additional documentation is attached. The transferor's and the transferee's designated representatives must sign and date the application certifying that all information is true, correct, and complete.

(2) *Application for transfer of crab IPQ*—(i) *Completed application.* NMFS will process a request for transfer of crab individual processor quota (IPQ)

provided that a paper or electronic request form is completed, with all information fields accurately filled in, and all required additional documentation is attached.

(ii) *Certification of transferor*—(A) *Non-electronic submittal.* The transferor's designated representative must sign and date the application certifying that all information is true, correct, and complete.

(B) *Electronic submittal.* The transferor's designated representative must submit the application as indicated on the computer screen. By using the transferor's NMFS ID, password and Transfer Key and submitting the application, the designated representative certifies that all information is true, correct, and complete.

(iii) *Certification of transferee*—(A) *Non-electronic submittal.* The transferee's designated representative must sign and date the application certifying that all information is true, correct, and complete.

(B) *Electronic submittal.* The transferee's designated representative must submit the application as indicated on the computer screen. By using the transferee's NMFS ID, password and Transfer Key and submitting the application, the designated representative certifies that all information is true, correct, and complete.

(3) *Application for transfer of crab QS or PQS.* NMFS will process a request for transfer of crab quota share (QS) or crab processor quota share (PQS) provided that a paper request form is completed and notarized, with all information fields accurately filled in, and all required additional documentation is attached. The transferor's and the transferee's designated representatives must sign and date the application certifying that all information is true, correct, and complete.

* * * * *

11. In § 680.44, revise paragraph (a)(4)(iii) to read as follows:

§ 680.44 Cost recovery.

(a) * * *

(4) * * *

(iii) *Payment address.* Submit payment and related documents as instructed on the fee form; payments may also be submitted electronically to NMFS. Forms are available on the NMFS Alaska Region website at *http://alaskafisheries.noaa.gov*, or by contacting NMFS at: 800–304–4846, Option 2.

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[FR Doc. E9–12036 Filed 5–22–09; 8:45 am]

BILLING CODE 3510–22–S

Notices

Federal Register
Vol. 74, No. 99
Tuesday, May 26, 2009

DEPARTMENT OF AGRICULTURE

Rural Business-Cooperative Service

Notice of Solicitation of Applications (NOSA) for Inviting Applications for Renewable Energy Systems and Energy Efficiency Improvements Grants and Guaranteed Loans and Renewable Energy Feasibility Studies Grants Under the Rural Energy for America Program

AGENCY: Rural Business-Cooperative Service, USDA.

ACTION: Notice.

SUMMARY: This notice announces that Rural Business-Cooperative Service is accepting applications for fiscal year (FY) 2009 to purchase renewable energy systems and make energy efficiency improvements and to conduct feasibility studies for renewable energy systems for agriculture producers and rural small businesses in eligible rural areas. Funding will be available in the form of grants and loan guarantees. In addition to grants and loan guarantees, applicants may apply for combination loan guarantee and grant funding (combination package). Lastly, the Agency intends to publish a proposed rule that will amend the Rural Energy for America portion of the Rural Development Grants regulation, published October 15, 2008 [73 FR 61198], at 7 CFR part 5002, for feasibility study projects in calendar year 2009.

DATES: Complete applications under this Notice must be received by the appropriate USDA Rural Development State Office no later than 4:30 local time July 31, 2009. Neither complete nor incomplete applications received after this date and time will be considered, regardless of the postmark on the application.

The comment period for information collection under the Paperwork Reduction Act of 1995 continues through July 27, 2009. Comments on the paper work burden must be received by this date to be assured of consideration.

ADDRESSES: Application materials may be obtained by contacting one of Rural Development's Rural Energy Coordinators or by downloading through *http://www.grants.gov*.

Submit electronic applications at *http://www.grants.gov*, following the instructions found on this Web site. To use Grants.gov, all applicants (unless the applicant is an individual) must have a Dun and Bradstreet Data Universal Numbering System (DUNS) number, which can be obtained at no cost via a toll-free request line at 1–866–705–5711 or online at *http://fedgov.dnb.com/webform*. Submit completed paper applications to the Rural Development State Office in the State in which the applicant's proposed project is located.

Rural Development Rural Energy Coordinators

Note: Telephone numbers listed are not toll-free.

Alabama

Quinton Harris, USDA Rural Development, Sterling Centre, Suite 601, 4121 Carmichael Road, Montgomery, AL 36106–3683, (334) 279–3623. *Quinton.Harris@al.usda.gov*.

Alaska

Dean Stewart, USDA Rural Development, 800 West Evergreen, Suite 201, Palmer, AK 99645–6539, (907) 761–7722. *dean.stewart@ak.usda.gov*.

American Samoa (See Hawaii)

Arizona

Alan Watt, USDA Rural Development, 230 North First Avenue, Suite 206, Phoenix, AZ 85003–1706, (602) 280–8769. *Alan.Watt@az.usda.gov*.

Arkansas

Tim Smith, USDA Rural Development, 700 West Capitol Avenue, Room 3416, Little Rock, AR 72201–3225, (501) 301–3280. *Tim.Smith@ar.usda.gov*.

California

Philip Brown, USDA Rural Development, 430 G Street, #4169, Davis, CA 95616, (530) 792–5811. *Phil.brown@ca.usda.gov*.

Colorado

April Dahlager, USDA Rural Development, 655 Parfet Street, Room E–100, Lakewood, CO 80215, (720) 544–2909. *april.dahlager@co.usda.gov*.

Commonwealth of the Northern Marianas Islands—CNMI (See Hawaii)

Connecticut (see Massachusetts)

Delaware/Maryland

Bruce Weaver, USDA Rural Development, 1221 College Park Drive, Suite 200, Dover, DE 19904, (302) 857–3626. *Bruce.Weaver@de.usda.gov*.

Federated States of Micronesia (See Hawaii)

Florida/Virgin Islands

Joe Mueller, USDA Rural Development, 4440 NW. 25th Place, Gainesville, FL 32606, (352) 338–3482. *joe.mueller@fl.usda.gov*.

Georgia

J. Craig Scroggs, USDA Rural Development, 111 E. Spring St., Suite B, Monroe, GA 30655, Phone 770–267–1413 ext. 113. *craig.scroggs@ga.usda.gov*.

Guam (See Hawaii)

Hawaii/Guam/Republic of Palau/Federated States of Micronesia/Republic of the Marshall Islands/American Samoa/Commonwealth of the Northern Marianas Islands—CNMI

Tim O'Connell, USDA Rural Development, Federal Building, Room 311, 154 Waianuenue Avenue, Hilo, HI 96720, (808) 933–8313. *Tim.Oconnell@hi.usda.gov*.

Idaho

Brian Buch, USDA Rural Development, 9173 W. Barnes Drive, Suite A1, Boise, ID 83709, (208) 378–5623. *Brian.Buch@id.usda.gov*.

Illinois

Molly Hammond, USDA Rural Development, 2118 West Park Court, Suite A, Champaign, IL 61821, (217) 403–6210. *Molly.Hammond@il.usda.gov*.

Indiana

Jerry Hay, USDA Rural Development, 2411 N. 1250 W., Deputy, IN 47230, (812) 873–1100. *Jerry.Hay@in.usda.gov*.

Iowa

Teresa Bomhoff, USDA Rural Development, 873 Federal Building, 210 Walnut Street, Des Moines, IA 50309, (515) 284–4447. *teresa.bomhoff@ia.usda.gov*.

Kansas

David Kramer, USDA Rural Development, 1303 SW First American Place, Suite 100, Topeka, KS 66604–4040, (785) 271–2744. *david.kramer@ks.usda.gov*.

Kentucky

Scott Maas, USDA Rural Development, 771 Corporate Drive, Suite 200, Lexington, KY 40503, (859) 224–7435. *scott.maas@ky.usda.gov*.

Louisiana

Kevin Boone, USDA Rural Development, 905 Jefferson Street, Suite 320, Lafayette, LA 70501, (337) 262–6601, Ext. 133. *Kevin.Boone@la.usda.gov*.

Maine

John F. Sheehan, USDA Rural Development, 967 Illinois Avenue, Suite 4, P.O. Box 405, Bangor, ME 04402–0405, (207) 990–9168. *john.sheehan@me.usda.gov*.

Maryland (see Delaware)

Massachusetts/Rhode Island/Connecticut

Charles W. Dubuc, USDA Rural Development, 451 West Street, Suite 2, Amherst, MA 01002, (401) 826–0842 X 306. *Charles.Dubuc@ma.usda.gov*.

Michigan

Traci J. Smith, USDA Rural Development, 3001 Coolidge Road, Suite 200, East Lansing, MI 48823, (517) 324–5157. *Traci.Smith@mi.usda.gov*.

Minnesota

Lisa L. Noty, USDA Rural Development, 1400 West Main Street, Albert Lea, MN 56007, (507) 373–7960 Ext. 120. *lisa.noty@mn.usda.gov*.

Mississippi

G. Gary Jones, USDA Rural Development, Federal Building, Suite 831, 100 West Capitol Street, Jackson, MS 39269, (601) 965–5457. *george.jones@ms.usda.gov*.

Missouri

Matt Moore, USDA Rural Development, 601 Business Loop 70 West, Parkade Center, Suite 235, Columbia, MO 65203, (573) 876–9321. *matt.moore@mo.usda.gov*.

Montana

John Guthmiller, USDA Rural Development, 900 Technology Blvd., Unit 1, Suite B, P.O. Box 850, Bozeman, MT 59771, (406) 585–2540. *John.Guthmiller@mt.usda.gov*.

Nebraska

Debra Yocum, USDA Rural Development, 100 Centennial Mall North, Room 152, Federal Building, Lincoln, NE 68508, (402) 437–5554. *Debra.Yocum@ne.usda.gov*.

Nevada

Herb Shedd, USDA Rural Development, 1390 South Curry Street, Carson City, NV 89703, (775) 887–1222. *herb.shedd@nv.usda.gov*.

New Hampshire (See Vermont)

New Jersey

Victoria Fekete, USDA Rural Development, 8000 Midlantic Drive, 5th Floor North, Suite 500, Mt. Laurel, NJ 08054, (856) 787–7752. *Victoria.Fekete@nj.usda.gov*.

New Mexico

Jesse Bopp, USDA Rural Development, 6200 Jefferson Street, NE., Room 255, Albuquerque, NM 87109, (505) 761–4952. *Jesse.bopp@nm.usda.gov*.

New York

Thomas Hauryski, USDA Rural Development, 415 West Morris Street, Bath, NY 14810, (607) 776–7398 Ext. 132, *Thomas.Hauryski@ny.usda.gov*.

North Carolina

David Thigpen, USDA Rural Development, 4405 Bland Rd. Suite 260, Raleigh, N.C. 27609, 919–873–2065. *David.Thigpen@nc.usda.gov*.

North Dakota

Dennis Rodin, USDA Rural Development, Federal Building, Room 208, 220 East Rosser Avenue, P.O. Box 1737, Bismarck, ND 58502–1737, (701) 530–2068. *Dennis.Rodin@nd.usda.gov*.

Ohio

Randy Monhemius, USDA Rural Development, Federal Building, Room 507, 200 North High Street, Columbus, OH 43215–2418, (614) 255–2424. *Randy.Monhemius@oh.usda.gov*.

Oklahoma

Jody Harris, USDA Rural Development, 100 USDA, Suite 108, Stillwater, OK 74074–2654, (405) 742–1036. *Jody.harris@ok.usda.gov*.

Oregon

Don Hollis, USDA Rural Development, 1229 SE Third Street, Suite A, Pendleton, OR 97801–4198, (541) 278–8049, Ext. 129. *Don.Hollis@or.usda.gov*.

Pennsylvania

Bernard Linn, USDA Rural Development, One Credit Union Place, Suite 330, Harrisburg, PA 17110–2996, (717) 237–2182. *Bernard.Linn@pa.usda.gov*.

Puerto Rico

Luis Garcia, USDA Rural Development, IBM Building, 654 Munoz Rivera Avenue, Suite 601, Hato Rey, PR 00918–6106, (787) 766–5091, Ext. 251. *Luis.Garcia@pr.usda.gov*.

Republic of Palau (See Hawaii)

Republic of the Marshall Islands (See Hawaii)

Rhode Island (see Massachusetts)

South Carolina

Shannon Legree, USDA Rural Development, Strom Thurmond Federal Building, 1835 Assembly Street, Room 1007, Columbia, SC 29201, (803) 253–3150. *Shannon.Legree@sc.usda.gov*.

South Dakota

Douglas Roehl, USDA Rural Development, Federal Building, Room 210, 200 4th Street, SW., Huron, SD 57350, (605) 352–1145. *doug.roehl@sd.usda.gov*.

Tennessee

Will Dodson, USDA Rural Development, 3322 West End Avenue, Suite 300, Nashville, TN 37203–1084, (615) 783–1350. *will.dodson@tn.usda.gov*.

Texas

Daniel Torres, USDA Rural Development, Federal Building, Suite 102, 101 South Main Street, Temple, TX 76501, (254) 742–9756. *Daniel.Torres@tx.usda.gov*.

Utah

Roger Koon, USDA Rural Development, Wallace F. Bennett Federal Building, 125 South State Street, Room 4311, Salt Lake City, UT 84138, (801) 524–4301. *Roger.Koon@ut.usda.gov*.

Vermont/New Hampshire

Cheryl Ducharme, USDA Rural Development, 89 Main Street, 3rd Floor, Montpelier, VT 05602, 802–828–6083. *cheryl.ducharme@vt.usda.gov*.

Virginia

Laurette Tucker, USDA Rural Development, Culpeper Building, Suite 238, 1606 Santa Rosa Road, Richmond, VA 23229, (804) 287–1594. *Laurette.Tucker@va.usda.gov*.

Virgin Islands (see Florida)

Washington

Mary Traxler, USDA Rural Development, 1835 Black Lake Blvd., SW., Suite B, Olympia, WA 98512, (360) 704–7762. *Mary.Traxler@wa.usda.gov*.

West Virginia

Richard E. Satterfield, USDA Rural Development, 75 High Street, Room 320, Morgantown, WV 26505–7500, (304) 284–4874. *Richard.Satterfield@wv.usda.gov*.

Wisconsin

Brenda Heinen, USDA Rural Development, 4949 Kirschling Court, Stevens Point, WI 54481, (715) 345–7615, Ext. 139. *Brenda.Heinen@wi.usda.gov*.

Wyoming

Jon Crabtree, USDA Rural Development, Dick Cheney Federal Building, 100 East B Street, Room 1005, P.O. Box 11005, Casper, WY 82602, (307) 233–6719. *Jon.Crabtree@wy.usda.gov*.

FOR FURTHER INFORMATION CONTACT: For information about this Notice, please contact the USDA Rural Development—Energy Division, Program Branch, STOP 3225, Room 6870, 1400 Independence Avenue, SW., Washington, DC 20250–3225. Telephone: (202) 720–1400.

For assistance on this program, please contact the applicable Rural Development's Rural Energy Coordinator, as provided in the **ADDRESSES** section of this notice.

SUPPLEMENTARY INFORMATION:

Paperwork Reduction Act

In accordance with the Paperwork Reduction Act of 1995, Rural Development will seek OMB approval of the reporting and recordkeeping requirements contained in this Notice and hereby opens a 60-day public comment period.

The Rural Energy for America Program, formerly section 9006 under the 2002 Farm Bill, is composed of several types of grants and guaranteed loan programs. These are: Guaranteed loans and grants for the development/construction of renewable energy systems and for energy efficiency improvement projects; grants for conducting energy audits; grants for conducting renewable energy development assistance; and grants for conducting renewable energy feasibility studies.

The information collection request for this notice is specifically for renewable energy feasibility study grants, which are newly authorized under REAP. The information collection burden associated with the renewable energy system and energy efficiency improvement projects are currently approved under OMB Control Number 0570–0050. The information collection burden associated with the energy audit and renewable energy development assistance grants is under review by OMB.

As noted above, this is a new information collection for the renewable energy system feasibility study grant portion of this Notice. Thus, the burden estimates reported in this notice are associated only with the feasibility study grants, and the Agency is asking for comment only on the burden estimates for these feasibility study grants. Once approved, the Agency intends to merge and incorporate the burden for feasibility study grants, reported in this notice, into the burden for the consolidated grant rule information collection that is pending OMB approval.

Title: Renewable Energy Feasibility Study Grants (part of the Renewable Energy for America Program).

Type of Request: New collection.

Abstract: Under this Notice, the Agency is providing grants to eligible applicants for the provision of renewable energy system feasibility studies to agricultural producers and rural small businesses.

The collection of information is vital to the Agency to make wise decisions regarding the eligibility of applicants and their projects in order to ensure compliance with the provisions of this Notice. Applicants seeking a grant will have to submit applications that include specific information about the applicant and the proposed feasibility study (e.g., the renewable energy project for which the study will be conducted; matching funds), and the experience of the entity that will be conducting the feasibility study. In sum, this collection of information is necessary in order to implement this Program.

The following estimates are based on the average over the first three years the program is in place.

Estimate of Burden: Public reporting burden for this collection of information is estimated to average 1.4 hours per response.

Respondents: Agricultural producers and rural small businesses.

Estimated Number of Respondents: 354.

Estimated Number of Responses per Respondent: 9.6.

Estimated Number of Responses: 3,395.

Estimated Total Annual Burden (hours) on Respondents: 4,701.

Copies of this information collection may be obtained from Cheryl Thompson, Regulations and Paperwork Management Branch, at (202) 692–0043.

Comments

Comments are invited on: (a) Whether the proposed collection of information is necessary for the proper performance of the functions of Rural Development, including whether the information will have practical utility; (b) the accuracy of Rural Development'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 Cheryl Thompson, Regulations and Paperwork Management Branch, Support Services Division, 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.

Overview Information

Federal Agency Name. Rural Business—Cooperative Service.

Funding Opportunity Title. Renewable Energy Systems and Energy Efficiency Improvements Grants and Guaranteed Loans and Renewable Energy Feasibility Studies Grants under the Rural Energy for America Program.

Announcement Type. Initial announcement.

Catalog of Federal Domestic Assistance (CFDA) Number. This program is listed in the Catalog of Federal Domestic Assistance under Number 10.868.

Dates. All applications must be completed and received in the appropriate United States Department of Agriculture (USDA) State Rural Development Office no later than 4:30 p.m. local time July 31, 2009. Applications received after 4:30 p.m. local time July 31, 2009, regardless of the application's postmark, will be returned to the applicant with no action.

Availability of Notice. This Notice is available on the USDA Rural Development Web site at *http://www.rurdev.usda.gov/rbs/busp/9006grant.htm.*

Notice Structure. Submission information specific to renewable energy system projects and energy efficiency improvement projects is found in Section IV and submission information specific to renewable energy system feasibility study projects is found in Section V. Requirements specified elsewhere in this Notice apply to all projects, unless otherwise stated.

I. Funding Opportunity Description

A. *Purpose.* This Notice is issued pursuant to section 9001 of the Food, Conservation, and Energy Act of 2008 (2008 Farm Bill), which amends section 9006 of the Farm Security and Rural Investment Act of 2002 (FSRIA), which establishes the Rural Energy for America Program under section 9007 of the 2008 Farm Bill. The program is designed to help agricultural producers and rural small businesses reduce energy costs and consumption and help meet the Nation's critical energy needs. The 2008 Farm Bill mandates the maximum percentages of funding that USDA Rural Development will provide. Within the maximum funding amounts specified in this Notice, funding approved for guaranteed loan only requests and for combination guaranteed loan and grant requests will not exceed 75 percent of eligible project costs, with the grant portion not to exceed 25 percent of eligible project costs, whether the grant is part of a combination request or is a stand-alone grant.

B. *Statutory Authority.* This program is authorized under Title IX, Section 9001, of the Food, Conservation, and Energy Act of 2008 (Pub. L. 110–246).

C. *Definition of Terms.* The following terms and the terms defined in 7 CFR part 4280 are applicable to this Notice. If this Notice and 7 CFR part 4280 both define the same term, that term shall have the meaning provided in this Notice.

Administrator. The Administrator of Rural Business—Cooperative Service within the Rural Development Mission Area of the U.S. Department of Agriculture.

Departmental regulations. The regulations of the Department of Agriculture's Office of Chief Financial Officer (or successor office) as codified in 7 CFR parts 3000 through 3099, including but not necessarily limited to 7 CFR parts 3015 through 3019, 7 CFR part 3021, and 7 CFR part 3052, and successor regulations to these parts.

EEI. Energy efficiency improvement.

Energy efficiency hydropower projects. Projects that improve the efficiency of an existing hydropower system, such as replacement equipment.

Hydropower. Energy created by use of various types of moving water including, but not limited to, ocean movement (tidal, wave, current, or thermal changes); diverted run-of-river water; in-stream run-of-river water; in-conduit water; or geothermally heated surface water.

Public power entity. Is defined using the definition of state utility as defined in section 217(A)(4) of the Federal Power Act (16 U.S.C. 824q(a)(4)). As of this writing, the definition is a State or any political subdivision of a State, or any agency, authority, or instrumentality of any one or more of the foregoing, or a corporation that is wholly owned, directly or indirectly, by any one or more of the foregoing, competent to carry on the business of developing, transmitting, utilizing, or distributing power.

Rated power. The amount of energy that can be created at any given time.

Renewable biomass.

(i) Materials, pre-commercial thinnings, or invasive species from National Forest System land and public lands (as defined in section 103 of the Federal Land Policy and Management Act of 1976 (43 U.S.C. 1702)) that:

(A) Are byproducts of preventive treatments that are removed to reduce hazardous fuels; to reduce or contain disease or insect infestation; or to restore ecosystem health;

(B) would not otherwise be used for higher-value products; and

(C) are harvested in accordance with applicable law and land management plans and the requirements for old-growth maintenance, restoration, and management direction of paragraphs (e)(2), (e)(3), and (e)(4) and large-tree retention of paragraph (f) of subsection of section 102 of the Healthy Forests Restoration Act of 2003 (16 U.S.C. 6512); or

(ii) Any organic matter that is available on a renewable or recurring basis from non-Federal land or land belonging to an Indian or Indian tribe that is held in trust by the United States or subject to a restriction against alienation imposed by the United States, including:

(A) Renewable plant material, including feed grains; other agricultural commodities; other plants and trees; and algae; and

(B) Waste material, including crop residue; other vegetative waste material (including wood waste and wood residues); animal waste and byproducts (including fats, oils, greases, and manure); and food waste and yard waste.

Renewable energy. Energy derived from:

(i) A wind, solar, renewable biomass, ocean (including tidal, wave, current, and thermal), geothermal or hydroelectric source; or

(ii) Hydrogen derived from renewable biomass or water using wind, solar, ocean (including tidal, wave, current, and thermal), geothermal or hydroelectric energy sources.

Renewable energy hydropower project. A new energy generation project that uses moving water as the feedstock equivalent.

RES. Renewable energy system.

Small hydropower. A hydropower project for which the rated power of the system is 30 megawatts or less.

II. Funding Information

A. *Available Funds.* The amount of funds available for renewable energy system feasibility studies in FY 2009 will be not more than 10 percent of the funds made available under the Rural Energy for America Program. The balance of the funds unused for the energy audit and renewable energy development assistance grants and the feasibility study grants will be available to the renewable energy systems and energy efficiency improvements projects under this program in FY 2009.

B. *Number of awards.* The number of awards will depend on the number of eligible applicants participating in this program.

C. *Grant Funding Limitations.* For the purposes of this Notice, the maximum amount of grant assistance to one individual or entity will not exceed $750,000 for FY 2009 under the Rural Energy for America Program. The Agency will not use less than 20 percent of the funds allocated for grants of $20,000 or less and not more than 10 percent of funds for grants to conduct renewable energy system feasibility studies.

D. *Types of Instrument.* Grant, guaranteed loan, and grant/guaranteed loan combinations. Only grants are available to conduct renewable energy system feasibility studies.

III. Application Submission Information

Applicants seeking to participate in this program must submit applications in accordance with this Notice and 7 CFR part 4280, subpart B, as applicable. Applicants must submit complete applications in order to be considered. Note that for the Agency to consider an application, the application must include all environmental review documents with supporting documentation in accordance with 7 CFR part 1940 subpart G.

A. Where To Obtain Applications

Applicants may obtain applications from applicable Rural Development Rural Energy Coordinator, as provided in the **ADDRESSES** section of this Notice. In addition, for grant applications, applicants may access the electronic grant application for the Rural Energy for America Program at *http://www.Grants.gov.* To locate the downloadable application package for this program, the applicant must use the program's CFDA Number (i.e., 10.868) or FedGrants Funding Opportunity Number, which can be found at *http://www.Grants.gov.* To use Grants.gov, all applicants must have a Dun and Bradstreet Data Universal Numbering System (DUNS) number, (unless the applicant is an individual) which can be obtained at no cost via a toll-free request line at 1–866–705–5711 or online at *http://fedgov.dnb.com/webform.*

B. When To Submit

Submit applications to the appropriate USDA Rural Development State Office by July 31, 2009. All applications must be received at the appropriate State Office by 4:30 p.m. local time on the deadline date.

C. Where To Submit

All applications are to be submitted to the Rural Development Rural Energy Coordinator in the State in which the applicant's proposed project is located. A list of Rural Development Rural Energy Coordinators is provided in the **ADDRESSES** section of this Notice. Alternatively, for grant applications, applicants may submit grant applications to the Agency via the Grants.gov Web site.

D. How To Submit

Applicants may submit applications as either hard copy or electronically as specified in the following paragraphs. When submitting an application as hard copy, applicants must submit one original and one copy of the complete application.

(1) *Grant applications.* Grant applications may be submitted either as hard copy to the appropriate Rural Development Rural Energy Coordinator or electronically using the government-wide Grants.gov Web site. Users of Grants.gov who download a copy of the application package may complete it off line and then upload and submit the application via the Grants.gov site, including all information typically included on the application, and all necessary assurances and certifications. After electronically submitting an application through the Web site, the applicant will receive an automated acknowledgement from Grants.gov that contains a Grants.gov tracking number.

(2) *Guaranteed loan applications.* Guaranteed loan only applications (i.e., those that are not part of a guaranteed loan/grant combination request) must be submitted as hard copy.

(3) *Guaranteed loan/grant combination applications.* Applications for guaranteed loans/grants (combination applications) must be submitted as hard copy.

F. Other Submission Requirements and Information

(1) *Application restrictions.* Applications submitted under this

Notice are subject to the following restrictions:

(i) Applicants can apply for only one renewable energy system project, one energy efficiency improvement project, and one renewable energy system feasibility study project under this Notice. A renewable energy system application cannot be submitted in FY2009 if a feasibility study grant application has been submitted in FY2009 for the same renewable energy system project.

(ii) Technical reviews of complete applications are conducted on a rolling basis. Once the technical review of a complete application has been completed, the applicant will not be allowed to modify or resubmit the application.

(2) *Eligibility considerations.* Eligibility is limited to projects that have completed the environmental review process according to 7 CFR 4280.114(d); demonstrated project eligibility according to 7 CFR 4280.108; except for renewable energy feasibility studies, demonstrated technical feasibility; and are complete will be eligible for funding consideration.

(3) *Grants.gov.* When you enter the Grants.gov site, you will find information about submitting an application electronically through the site as well as the hours of operation. USDA Rural Development strongly recommends that applicants do not wait until the application deadline date to begin the application process through Grants.gov.

(4) *Original signatures.* USDA Rural Development may request that the applicant provide original signatures on forms submitted through Grants.gov at a later date.

(5) *Intergovernmental review.* The Rural Energy for America Program is subject to the provisions of Executive Order 12372, which requires intergovernmental consultation with State and local officials.

(6) *Award considerations.* For renewable energy systems and energy efficiency improvements, in determining the amount of a loan guarantee or grant provided, the Agency shall take into consideration the following six criteria:

(i) The type of renewable energy system to be purchased;

(ii) The estimated quantity of energy to be generated by the renewable energy system;

(iii) The expected environmental benefits of the renewable energy system;

(iv) The quantity of energy savings expected to be derived from the activity, as demonstrated by an energy audit;

(v) The estimated period of time for the energy savings generated by the activity to equal the cost of the activity; and

(vi) The expected energy efficiency of the renewable energy system.

G. Hydropower Eligibility

For the purposes of this Notice, only hydropower projects with a rated power of 30 megawatts or less are eligible. The Agency refers to these hydropower sources as ''small hydropower,'' which includes hydropower projects commonly referred to as ''micro-hydropower'' and ''mini-hydropower.''

IV. Program Provisions Specific to Renewable Energy Systems and Energy Efficiency Improvements

This section of the notice identifies what information renewable energy system and energy efficiency improvement (RES/EEI) applications are to contain, funding limitations, and other submission requirements and award information. Except as provided in this Notice, RES/EEI applications are to follow the provisions specified in 7 CFR 4280, subpart B.

A. Project Eligibility

In addition to the project eligibility requirements specified in § 4280.108, no renewable energy system or energy efficiency improvement, or portion thereof, can be used for any residential purpose, including any residential portion of a rural small business, farm, ranch, or agricultural facility. However, an applicant may apply for funding for the installation of a second meter or provide certification in the application that any excess power generated by the renewable energy system will be sold to the grid and will not be used by the applicant for residential purposes.

B. Applications

In addition to the requirements found in 7 CFR part 4280, subpart B, the following also applies to RES/EEI applications submitted under this Notice.

(1) *One funding type applications.* Only one type of funding application (grant-only, guaranteed loan-only, or guaranteed loan/grant combination) for each project can be submitted.

(2) *Environmental information.* Each application must include all environmental review documents with supporting documentation in accordance with 7 CFR part 1940 subpart G.

(3) *Foreign technology.* As stated in 7 CFR 4280.108, projects must be for a pre-commercial or commercially available technology. The definition of ''pre-commercial'' and ''commercial'' are at 7 CFR 4280.103. The Agency's position is that if the system is currently commercially available only outside the United States (U.S.), then applicants must provide authoritative evidence of the foreign operating history, performance, and reliability in order to address the proven operating history identified in the definition. ''Commercial'' applicants must provide evidence that professional service providers, trades, large construction equipment providers and labor are readily available domestically and familiar with installation procedures and practices, and spare parts and service are readily available in the U.S. to properly maintain and operate the system. All warranties must be valid in the U.S.

(4) *Commercial application demonstration of precommercial technologies.* In accordance with the definition of ''pre-commercial'' technology found in 7 CFR 4280.103, technical and economic potential for commercial application must be demonstrated to the Agency. In order to demonstrate the system has emerged through research and development as well as the demonstration process, applicants must provide authoritative evidence of the operating history, performance, and reliability past completion of start-up, shake-down, and commissioning. Typically, and in line with financial and operating performance evaluation protocol, the documented operating history, which may be established domestically or outside the U.S., should provide performance data for a minimum of 12 months. The time period will address the economic and technical performance potential of the pre-commercial technology, as defined in 7 CFR 4280.103. Lastly, in accordance with demonstrating the potential for commercial application, applicants must provide evidence that professional service providers, trades, large construction equipment providers, and labor are potentially available domestically and sufficiently familiar with installation procedures and practices, and spare parts and service are available in the U.S. to properly maintain and operate the system. Any warranties would have to be valid in the U.S.

(5) *Format.* To ensure that projects are accurately scored by the Agency, applicants are requested to tab and number each evaluation criteria and include, in that section, its corresponding supporting documentation and calculations according to 7 CFR 4280.112.

(6) *Technical report appendices.* Technical reports for hydropower projects shall conform to Appendix A of this Notice. Technical reports for other renewable energy projects shall continue to conform to Appendix A or B, as applicable, to 7 CFR part 4280, subpart B.

D. Funding Limitations

(1) *Grant-only applications.* For renewable energy system grants, the minimum grant is $2,500 and the maximum is $500,000. For energy efficiency improvement grants, the minimum grant is $1,500 and the maximum grant is $250,000.

(2) *Loan guarantee-only applications.* For loan guarantees, the minimum guaranteed loan amount is $5,000 and the maximum amount of a guarantee to be provided to a borrower is $25 million. The maximum loan guarantee for a guaranteed loan in excess of $10 million is 60%. For FY 2009, the guarantee fee amount is 1 percent of the guaranteed portion of the loan and the annual renewal fee is 0.250 percent (one-quarter of one percent) of the guaranteed portion of the loan.

(3) *Guaranteed loan and grant combination applications.* Funding for grant and loan combination packages are subject to the funding limitations specified in paragraphs (1) and (2) of this section. For grant and loan combination packages, the minimum grant portion of the combined funding request is $1,500 for energy efficiency improvement projects and $2,500 for renewable energy system projects. All grant and loan combination packages will be funded from the same allocation as loan guarantees.

E. Award Process

In addition to the process for awarding funding under 7 CFR part 4280, subpart B, the Agency will make awards using the following considerations:

(1) *Scoring criteria.* In addition to the criteria specified in § 4280.112(e), the Agency will award 10 points to grant-only applications requesting $20,000 or less.

(2) *Technical review.* Every RES/EEI application will receive a technical review. No RES/EEI application will receive more than one technical review.

(3) *Demonstrated financial need.* As required in §§ 4280.108(a)(5), 4280.109(b)(2), and 4280.193(a), the applicant for a grant or combination guaranteed loan and grant must demonstrate financial need. Only those packages that demonstrate financial need will be considered for funding.

(4) *Combination applications.* To ensure equitable competition and high quality projects, the grant portion of a combination application must score at least 20 points for technical merit. Only those combination packages that score a sufficient amount of technical merit points will be considered for funding. Applicants whose combination applications are approved for funding must accept and utilize both the loan and the grant.

(5) *Grant-only applications of $20,000 or less.* As directed by statute, the Agency will use not less than 20 percent of the funds allocated to the Rural Energy for America Program for grants of $20,000 or less. The Agency will establish a reserve at the National Office and States with grant-only requests of $20,000 or less may request funds from the reserve.

(6) *Change of contractor or vendor.* After an award has been made, the recipient of the award can request to change a contractor or vendor if the technical merit score for the project remains the same or is higher. Prior to changing a contractor or vendor, the recipient must submit to the Agency a written request providing information that allows the Agency to rescore the project's technical merit. If the Agency determines that the project achieves the same or higher technical merit score, the recipient may make the change. No additional funding will be available from the Agency if costs for the project have increased. If the Agency determines that the project does not achieve the same or higher technical merit score, the change will not be approved.

(7) *Intergovernmental review.* If State or local governments raise objections to a proposed project under the intergovernmental review process that are not resolved within 90 days of the Agency's selection of the application, the Agency will rescind the selection and will provide the applicant with a written notice to that effect.

V. Program Provisions for Renewable Energy Feasibility Study Grants

Under 7 CFR part 4280, subpart B, certain renewable energy system project applications must include a business level feasibility study (*see* § 4280.111(b)(8)). Such feasibility studies are now an eligible purpose under the Rural Energy for America Program for which a grant may be awarded. This section of the Notice identifies the procedures the Agency will use to process and select such feasibility study applications, award grants, and administer such financial assistance.

A. Existing Regulations

Applicants submitting applications for feasibility studies are subject to the provisions of this Notice and to the grant provisions of 7 CFR part 4280, subpart B, as may be modified under this section of this Notice.

B. Specific Requirements for This Notice

As noted in the previous paragraph, the grant provisions of 7 CFR part 4280, subpart B, apply to applicants and their applications submitted under this Notice except as modified in this section of this Notice.

(1) *Applicant eligibility.* In order to be eligible for a feasibility study grant under this Notice, the applicant must:

(i) be a rural small business or agricultural producer as defined in § 4280.103, and

(ii) meet the eligibility criteria of § 4280.107.

(2) *Project eligibility.* Feasibility studies must be for a renewable energy system that:

(i) is for the purchase, installation, expansion, or other energy-related improvement of a renewable energy system;

(ii) is located in a rural area; and

(iii) is for technology that is pre-commercial or commercially available, and that is replicable.

(3) *Grant funding.* The maximum amount for a feasibility study grant under this Notice is $50,000 or 25 percent of the eligible project cost (as described below) of the study, whichever is less. The grantee will have 2 years from the date of the grant agreement to provide the Agency with a complete and acceptable feasibility study and to request disbursement of the funds as described in Section V(12) of this notice. If the grantee does not submit to the Agency a complete and acceptable feasibility study within this 2 year period, the grant is subject to termination by and reimbursement to the Agency according to 7 CFR 3015.

(4) *Eligible project costs.* Only those costs incurred after the application date specific to the development of the feasibility study (refer to Appendix B for further information on the content of a feasibility study) will be considered by the Agency in determining the size of the grant.

(5) *Application restrictions.* Feasibility study applications:

(i) can only be submitted as a stand-alone grant application;

(ii) cannot be submitted for a renewable energy system project for which a feasibility study has been conducted or funded under any Federal or State program;

(iii) can be submitted for a modification to an existing renewable energy system (e.g., for the expansion portion of an existing windmill farm); and

(iv) cannot be submitted in FY 2009 for a RES project if an RES application for the same renewable energy system is submitted in FY 2009 and vice versa.

(6) *Applications.* An original and one complete copy of each application are required that follow the outline below. Each application must include a Table of Contents with clear pagination and chapter identification and the following:

(i) Form SF 424, Application for Federal Assistance;

(ii) Form SF–424B, Assurances—Non-Construction Programs;

(iii) If an entity, one copy of the applicant's organizational documents; and

(iv) A proposed work plan, which includes:

(A) a brief description of the proposed system the feasibility study will evaluate;

(B) a description of the feasibility study to be conducted. An acceptable feasibility study is outlined in Appendix B to this Notice. Applicants must require those conducting the feasibility study to consider and document within the feasibility study the important environmental factors within the planning area and the potential environmental impacts of the project for which the feasibility study is being conducted, as well as the alternatives considered.

(C) the timeframe for completion of the feasibility study;

(D) the experience of the company/individual completing the feasibility study, including the number of similar projects the company/individual has performed, the number of years the company has been performing a similar service, and corresponding resumes;

(E) the source and amount of other project funds needs to be clearly identified. Agency approved written documentation/confirmation from any third party committing a specific amount of such funds is required. Documentation includes such items as bank statements, lender commitment letters, and so forth;

(F) sufficient financial information to allow the Agency to determine the applicant's size. All information submitted under this paragraph must be substantiated by authoritative records.

(*1*) If the applicant is a rural small business, provide sufficient information to determine its total annual receipts and number of employees and the same information for any parent, subsidiary, or affiliates at other locations. Voluntarily providing tax returns is one means of satisfying this requirement. The information provided must be sufficient for the Agency to make a determination of business size as defined by SBA.

(*2*) If the applicant is an agricultural producer, provide the gross market value of the agricultural products, gross agricultural income, and gross nonfarm income of the applicant for the calendar year preceding the year in which the application is submitted; and

(G) any Intergovernmental review comments from the State Single Point of Contact, or evidence that the State has elected not to review the program under Executive Order 12372; and

(H) A certification that the applicant has not received any other Federal or State assistance for a feasibility study for the subject renewable energy system.

(7) *Evaluation of applications.* Feasibility study applications submitted under this Notice will be evaluated by the applicable Rural Energy Coordinator for eligibility, completeness, and scoring.

(i) *General review.* The Agency will evaluate each application and make a determination as to whether the applicant is eligible, the proposed grant is for an eligible feasibility study, and the proposed grant complies with all applicable statutes and regulations.

(A) *Applicant eligibility.* The Agency will first determine whether the entity is eligible to compete for a feasibility study grant. Applications for applicants determined by the Agency not to be eligible will not be processed further. The Agency will determine applicant eligibility based on the criteria specified in this section.

(B) *Proposal eligibility.* After determining applicant eligibility, the Agency will review the application to determine if the proposal is eligible. Applications determined by the Agency not to be eligible will not be processed further. The Agency will determine whether the application contains certification by the applicant that the applicant has neither sought nor received any other Federal or State assistance for a feasibility study on the subject facility. If the application does not contain such certification, it is an ineligible application and the Agency will stop processing the application. If the application contains such certification, the Agency will continue processing it.

(ii) *Ineligible applicants and applications.* If either the applicant or the application is ineligible, the Agency will inform the applicant in writing of the decision, reasons therefore, and any appeal rights. No further evaluation of the application will occur.

(iii) *Incomplete applications.* If the application is incomplete, the Agency will return it to the applicant. The Agency will identify those parts of the application that are incomplete. The applicant may resubmit the application, as long as it is received prior to the July 31, 2009, deadline date.

(8) *Scoring applications.* The Agency will assign a score to each eligible application as follows:

(i) *Energy replacement or generation.* The project can be for either replacement or generation, but not both. A maximum of 25 points can be awarded under this section.

(A) *Energy replacement.* 25 points will be awarded if proposed project will offset a portion or all of the applicants energy needs.

(B) *Energy generation.* 15 points will be awarded if the proposed renewable energy system is intended primarily for production of energy for sale.

(ii) *Commitment of funds for the feasibility study.* Other federal or state assistance for only the feasibility study would make the request ineligible. Appropriate documentation must verify commitment. A maximum of 10 points can be awarded under this section.

(A) 10 points—100% of matching funds.

(B) 7.5 points—75% up to, but not including 100% of matching funds.

(C) 5 points—50% up to, but not including 75% of matching funds.

(D) 0 points—less than 50% of matching funds.

(iii) *Designation as a small agricultural producer/very small business.* An applicant will be considered either an agricultural producer or rural small business. No applicant will be considered as both. Points will only be awarded under either paragraph (iii)(A) or (iii)(B). A maximum of 20 points can be awarded under this section.

(A) For an Agricultural Producer:

(*1*) 10 points will be awarded if the applicant is an agricultural producer producing agricultural products with a gross market value of less than $600,000 in the preceding year, or

(*2*) 20 points will be awarded if the applicant is an agricultural producer producing agricultural products with a gross market value of less than $200,000 in the preceding year.

(B) For a Rural Small Business, 20 points will be awarded if the applicant is a very small business, as defined in § 4280.103.

(iv) *Experience and qualifications of the entity identified to perform the feasibility study.* A maximum of 15 points can be awarded under this section.

(A) 15 points will be awarded if the entity has 5 or more years experience in the field of study for the technology field being proposed.

(B) 7.5 points will be awarded if the entity has 2 or more years, but less than 5 years, experience in the field of study for the technology field being proposed.

(C) 0 points will be awarded if the entity has less than 2 years experience in the field of study for the technology field being proposed.

(v) *Size of feasibility study grant request.* A maximum of 20 points can be awarded under this section.

(A) 20 points will be awarded if the feasibility study request is $10,000 or less.

(B) 10 points will be awarded if the feasibility study request is more than $10,000 up to $25,000.

(C) 0 points will be awarded if the feasibility study request is greater than $25,000.

(vi) *Resources to implement project.* Considering the technology being proposed, the applicant may qualify for other local or State Programs to assist in the construction, or operation of the facility. These programs will benefit the applicant and/or proposed project during or after the facility is constructed and operational. A maximum of 10 points can be awarded under this section.

(A) 5 points will be awarded if the applicant has identified local programs.

(B) 5 points will be awarded if the applicant has identified State programs.

(9) *Award Process.* The Agency will use the following process to determine which grants receive funding under this Notice.

(i) *Ranking of applications.* All scored applications will be ranked by the Agency as soon after the application deadline as possible. All applications that are ranked will be considered for selection for funding.

(ii) *Selection of applications for funding.* Applications will be selected based on their rank in accordance with their scores. If, after the majority of applications have been funded, insufficient funds remain to fund the next highest scoring application, the Agency may elect to fund a lower scoring application. Before this occurs, the Agency will provide the applicant of the higher scoring application the opportunity to reduce the amount of its grant request to the amount of funds available. If the applicant agrees to lower its grant request, it must certify that the purposes of the project can be met, and the Agency must determine the project is financially feasible at the lower amount. The Agency will notify, in writing, applicants whose applications have been selected for funding.

(iii) *Disposition of ranked applications not funded.* Based on the availability of funding, a ranked application may not be funded in the fiscal year in which it was submitted. Such ranked applications will not be carried forward into the next fiscal year and the Agency will notify the applicant in writing.

(10) *Actions prior to grant closing.*

(i) *Environmental.* If construction is a component of the study, the appropriate level of environmental assessment must be completed prior to the obligation of funds. All feasibility study grants made under this Notice are subject to the requirements of subpart G of part 1940 of this title. When construction is not a component of the study, feasibility studies are considered planning assistance, which are categorically excluded from the environmental review process by § 1940.333 of this title.

(ii) *Changes in project cost or scope.* If there is a significant reduction in project cost or changes in project scope, the applicant's funding needs, eligibility, and scoring, as applicable, will be reassessed. Decreases in Agency funds will be based on revised project costs and other selection factors; however, other factors, including Agency regulations used at the time of grant approval, will remain the same. Obligated grant funds not needed to complete the project will be de-obligated.

(iii) *Evidence of other funds.* Applicants expecting funds from other sources for use in completing projects being partially financed with Agency funds will present evidence of the commitment of these funds from such other sources.

(11) *Approval Process.*

(i) *Letter of conditions.* The Agency will notify the approved applicant in writing, setting out the conditions under which the grant will be made. The notice will include those matters necessary to ensure that the proposed grant is completed in accordance with the terms of the scope of work and budget, that grant funds are expended for the feasibility study, and that the applicable requirements prescribed in the relevant Department regulations are complied with. The Letter of Conditions will be sent to the applicant.

(ii) *Letter of Intent to Meet Conditions.* Upon reviewing the conditions and requirements in the letter of conditions, the applicant must complete, sign and return a Form RD 1942–46, ''Letter of Intent to Meet Conditions,'' to the Agency; or if certain conditions cannot be met, the applicant may propose alternate conditions to the Agency. The Agency must concur with any changes proposed to the letter of conditions by the applicant before the application will be further processed.

(iii) *Grant agreement, forms, and certifications.* Prior to grant approval, the applicant must complete, sign, and return a grant agreement, which is attached to this notice as Appendix C. In addition, the following forms and certifications must be submitted prior to grant approval:

(A) Certification that the feasibility study grant will be for a renewable energy system project that is located in a rural area;

(B) Form AD–1047, ''Certification Regarding Debarment, Suspension, and Other Responsibility Matters—Primary Covered Transactions;''

(C) Form AD–1048, ''Certification Regarding Debarment, Suspension, Ineligibility and Voluntary Exclusion—Lower Tier Covered Transactions,'' including certification from any person or entity you do business with as a result of this government assistance that they are not debarred or suspended from government assistance;

(D) Form AD–1049, ''Certification Regarding Drug-Free Workplace Requirements (Grants) Alternative I—For Grantees Other Than Individuals;''

(E) Form SF–LLL, ''Disclosure Form to Report Lobbying'' or Exhibit A–1 of RD Instruction 1940–Q, ''Certification for Contracts, Grants, and Loans;'' and

(F) Form RD 400–4, ''Assurance Agreement.''

(iv) *Grant approval.* Form RD 1940–1 must be signed by the applicant.

(A) The applicant will be sent a copy of the executed Form RD 1940–1, the approved scope of work, and a grant agreement (see Appendix C to this Notice). The grant will be considered closed on the obligation date.

(B) The grantee must abide by all requirements contained in the Grant Agreement, this Notice, and any other applicable Federal statutes or regulations. Failure to follow the requirements may result in termination of the grant and adoption of other available remedies.

(12) *Fund disbursement.* Grant funds will be expended on a pro rata basis with matching funds.

(i) Requests for reimbursement may be submitted monthly or more frequently if authorized to do so by the Agency. Ordinarily, payment will be made within 30 days after receipt of a proper request for reimbursement.

(ii) The grantee shall not request reimbursement for the Federal share of amounts withheld from contractors to ensure satisfactory completion of work until after it makes those payments.

(iii) Payment shall be made by electronic funds transfer.

(iv) Standard Form 270, ''Request for Advance or Reimbursement,'' or other format prescribed by the Agency shall be used to request grant reimbursements.

(v) For renewable energy system feasibility studies, grant funds will be disbursed in accordance with the above through 90 percent of grant disbursement. The final 10 percent of grant funds will be held by the Agency until a feasibility study acceptable to the Agency has been submitted.

(13) *Deobligation of grant funds.* Funds remaining after all costs incident to the project have been paid or provided for are subject to deobligation.

(14) *Monitoring and reporting project performance.*

(i) *Monitoring of project.* Grantees are responsible for ensuring all activities are performed within the approved scope of work and that funds are only used for approved purposes. Grantees shall constantly monitor performance to ensure that time schedules are being met, projected work by time periods is being accomplished, financial resources appropriately expended by contractors (if applicable), and any other performance objectives identified in the scope of work are being achieved. To the extent resources are available, the Agency will monitor grantees to ensure that activities are performed in accordance with the Agency-approved scope of work and to ensure that funds are expended for approved purposes. The Agency's monitoring of Grantees neither relieves the Grantee of its responsibilities to ensure that activities are performed within the scope of work approved by the Agency and that funds are expended for approved purposes only nor provides recourse or a defense to the Grantee should the Grantee conduct unapproved activities, engage in unethical conduct, engage in activities that are or give the appearance of a conflict of interest, or expend funds for unapproved purposes.

(ii) *Financial status reports.* A SF–269, ''Financial Status Report,'' and a project performance activity report will be required of all grantees on a semiannual basis. The grantee will complete the project within the total sums available to it, including the grant, in accordance with the scope of work and any necessary modifications thereof prepared by grantee and approved by the Agency. The final Financial Status Report must be submitted to the Agency within 90 days after the feasibility study has been completed.

(iii) *Performance reports.* Grantees must submit to the Agency, in writing, semiannual performance reports and a final performance report. Grantees are to submit an original of each report to the Agency.

(A) *Semiannual performance reports.* Each semiannual performance report shall describe current progress and identify any problems, delays, or adverse conditions, if any, which have affected or will affect attainment of overall project objectives or prevent meeting time frame for completion of the feasibility study within two years. This disclosure shall be accompanied by a statement of the action taken or planned to resolve the situation.

(B) *Final performance report.* A final performance report, which will serve as the last semiannual performance report, will be required within 90 days after the feasibility study has been completed. The final performance report shall summarize any problems, delays, or adverse conditions, if any, which have affected the project objectives or prevented meeting time frames for completion of the feasibility study. The final performance report should indicate if the grantee intends to proceed with the construction of the project.

(iv) *Final deliverables.* Upon completion of the feasibility study, the grantee shall submit the following to the Agency:

(A) the project feasibility study; and

(B) SF–270, ''Request for Advance or Reimbursement.''

(v) *Reports required after feasibility study completion.* Beginning the first full year after the feasibility study has been completed, grantees shall report annually for 2 years on the following:

(A) Is the renewable energy system project for which the feasibility study was conducted underway? If yes, describe how far along the renewable energy system project is (e.g., financing has been secured, site has been secured, construction contracts are in place, project completed).

(B) Is the renewable energy system project complete? If so, what is the actual amount of energy being produced?

(vi) *Other reports.* The Agency may request any additional project and/or performance data for the project for which grant funds have been received.

(15) *Financial Management System and Records.* Grantees are required to maintain a financial management system and records in accordance with 7 CFR 3015.

(16) *Grant servicing.* Grants will be serviced in accordance with Departmental regulations and 7 CFR part 1951, subparts E and O. Grantees will permit periodic inspection of the project records and operations by a representative of the Agency. All non-confidential information resulting from the grantee's activities shall be made available to the general public on an equal basis.

(17) *Programmatic changes.* The Grantee shall obtain prior Agency approval for any change to the scope or objectives of the approved project. Failure to obtain prior approval of changes to the scope of work or budget may result in suspension, termination, and recovery of grant funds.

(18) *Transfer of obligations.* Subject to Agency approval, an obligation of funds established for a grantee may be transferred to a different (substituted) grantee provided:

(i) The substituted grantee

(A) is eligible;

(B) has a close and genuine relationship with the original grantee; and

(C) has the authority to receive the assistance approved for the original grantee; and

(ii) The type of renewable energy technology and the scope of the project for which the Agency funds will be used remain unchanged.

(19) *Grant closeout and related activities.* In addition to the requirements specified in the Departmental regulations, failure to submit satisfactory reports on time under the provisions of the Monitoring and Reporting Project Performance requirements of this Notice may result in the suspension or termination of a grant. The provisions of this section apply to grants and sub-grants.

VI. Administrative Information Applicable to This Notice

A. Notifications

(1) *Eligibility.* If an applicant is determined by the Agency to be eligible for participation, the Agency will notify the applicant in writing. If an applicant is determined by the Agency to be ineligible, the Agency will notify the applicant, in writing, as to the reason(s) the applicant was rejected. Such applicant will have appeal rights as specified in this Notice.

(2) *Award.* Each applicant will be notified of the Agency's decision on their application.

B. Administrative and National Policy Requirements

(1) *Review or appeal rights.* A person may seek a review of an Agency

decision under this Notice from the appropriate Agency official that oversees the program in question or appeal to the National Appeals Division in accordance with 7 CFR part 11 of this title. If the review or appeal involves a combination funding request, both the lender and borrower must request the review or appeal.

(2) *Notification.* If at any time prior to application approval it is decided that favorable action will not be taken on an application, the Agency will notify the applicant in writing of the decision and of the reasons why the request was not favorably considered. The notification will inform applicant officials of their rights to informal review, mediation, and appeal of the decision in accordance with 7 CFR part 11 and 7 CFR part 1900, subpart B.

C. Exception Authority

Except as specified in paragraphs (1) through (3) of this section, the Administrator may make exceptions to any requirement or provision of this Notice, if such exception is in the best financial interests of the Federal Government and is otherwise not in conflict with applicable laws.

(1) *Applicant eligibility.* No exception to applicant eligibility can be made.

(2) *Project eligibility.* No exception to project eligibility can be made.

(3) *Rural area definition.* No exception to the definition of rural area can be made.

D. Member or Delegate Clause

No member of or delegate to Congress shall receive any share or part of this grant or any benefit that may arise therefrom; but this provision shall not be construed to bar as a contractor under the grant a publicly held corporation whose ownership might include a member of Congress.

E. Other USDA Regulations

Feasibility study grants awarded under this Notice are subject to the provisions of the Department regulations, as applicable, which are incorporated by reference herein.

VII. Agency Contacts

Notice Contact. For further information about this Notice, please contact the USDA Rural Development-Energy Division, Program Branch, STOP 3225, Room 6867, 1400 Independence Avenue, SW., Washington, DC 20250–3225. Telephone: (202) 720–1400.

For assistance on this Notice, please contact one of Rural Development's Rural Energy Coordinators, as provided in the **ADDRESSES** section of this Notice.

VIII. Nondiscrimination Statement

USDA prohibits discrimination in all its programs and activities on the basis of race, color, national origin, age, disability, and where applicable, sex, marital status, familial status, parental status, religion, sexual orientation, genetic information, political beliefs, reprisal, or because all or part of an individual's income is derived from any public assistance program. (Not all prohibited bases apply to all programs.) Persons with disabilities who require alternative means for communication of program information (Braille, large print, audiotape, etc.) should contact USDA's TARGET Center at (202) 720–2600 (voice and TDD). To file a complaint of discrimination, write to USDA, Director, Office of Civil Rights, 1400 Independence Avenue, SW., Washington, DC 20250–9410, or call (800) 795–3272 (voice), or (202) 720–6382 (TDD). ''USDA is an equal opportunity provider, employer, and lender.''

IX. Civil Rights Compliance Requirements

All grants and guaranteed loans made under this Notice are subject to title VI of the Civil Rights Act of 1964 and part 1901, subpart E of this title.

Dated: May 18, 2009.

William F. Hagy III,

Acting Administrator, Rural Business-Cooperative Service.

Appendix A—Technical Reports for Hydropower Projects

The technical requirements specified in this appendix apply to all hydropower projects. Hydropower projects are those projects that create energy from moving water, including, but not necessarily limited to, ocean movement (tidal, wave, current, or thermal changes); diverted run-of-river water; in-stream run-of-river water; in-conduit water; or geo-thermally heated surface water.

The Technical Report for hydropower projects must demonstrate that the project design, procurement, installation, startup, operation, and maintenance of the renewable energy system will operate or perform as specified over its design life in a reliable and a cost-effective manner. The Technical Report must also identify all necessary project agreements, demonstrate that those agreements will be in place, and that necessary project equipment and services are available over the design life.

All technical information provided must follow the format specified in this appendix. Supporting information may be submitted in other formats. Design drawings and process flowcharts are encouraged as exhibits. A discussion of each topic is not necessary if the topic is not applicable to the specific project. Questions identified in the Agency's technical review of the project must be answered to the Agency's satisfaction before the application will be approved. The applicant must submit the original technical report plus one copy to the Rural Development State Office. Hydropower projects with total eligible project costs greater than $400,000 require the services of a licensed professional engineer (PE) or team of PEs. Depending on the level of engineering required for the specific project or if necessary to ensure public safety, the services of a licensed PE or a team of licensed PEs may be required for smaller projects.

(a) *Qualifications of project team.* The hydropower project team should consist of a system designer, a project manager, an equipment supplier, a project engineer, a construction contractor, and a system operator and maintainer. One individual or entity may serve more than one role. The project team must have demonstrated expertise in hydropower development, engineering, installation, and maintenance. Authoritative evidence that project team service providers have the necessary professional credentials or relevant experience to perform the required services must be provided. Authoritative evidence that vendors of proprietary components can provide necessary equipment and spare parts for the system to operate over its design life must also be provided. The application must:

(1) Discuss the proposed project delivery method. Such methods include a design, bid, build where a separate engineering firm may design the project and prepare a request for bids and the successful bidder constructs the project at the applicant's risk, and a design/build method, often referred to as turnkey, where the applicant establishes the specifications for the project and secures the services of a developer who will design and build the project at the developer's risk;

(2) Discuss the hydropower equipment manufacturers of major components being considered in terms of the length of time in business and the number of units installed at the capacity and scale being considered;

(3) Discuss the project manager, equipment supplier, system designer, project engineer, and construction contractor qualifications for engineering, designing, and installing hydropower systems, including any relevant certifications by recognized organizations. Provide a list of the same or similar projects designed, installed, or supplied and currently operating with references, if available; and

(4) Describe the system operator's qualifications and experience for servicing, operating, and maintaining hydropower projects. Provide a list of the same or similar projects designed, installed, or supplied and currently operating with references, if available.

(b) *Agreements, permits, and certifications.* Identify all necessary agreements and permits required for the project and the status and schedule for securing those agreements and permits, including the items specified in paragraphs (b)(1) through (6).

(1) Identify zoning and code issues and required permits and the anticipated schedule for meeting those requirements and securing those permits. This list should include all local, state, and federal permits required, estimated timeline for each permit and current status of acquiring each permit.

(2) Identify land use agreements required for the project and the anticipated schedule for securing the agreements and the term of those agreements.

(3) Identify available component warranties for the specific project location and size.

(4) For systems planning to interconnect with a utility, describe the utility's system interconnection requirements, power purchase arrangements, or licenses where required and the anticipated schedule for meeting those requirements and obtaining those agreements.

(5) Identify all environmental issues, including environmental compliance issues, associated with the project on Form RD 1940–20, ''Request for Environmental Information,'' and in compliance with 7 CFR part 1940, subpart G, of this title. (Note: The environmental review process, including all required publications must be completed prior to approval of any Rural Development funding.) The applicant may want to work with all federal organizations involved with the project, to promulgate a single environmental review document.

(6) Submit a statement certifying that the project will be installed in accordance with applicable local, State, and national codes, regulations, and permits.

(c) *Resource assessment.* Provide adequate and appropriate data to demonstrate the amount of renewable resource available. Indicate the quality of the resource, including temperature (if applicable), flow, and sustainability of the resource, including a summary of the resource evaluation process and the specifications of the measurement setup and the date and duration of the evaluation process and proximity to the proposed site. If less than 1 year of data is used, a qualified consultant must provide a detailed analysis of the correlation between the site data and a nearby, long-term measurement site.

(d) *Design and engineering.* Provide authoritative evidence that the system will be designed and engineered so as to meet its intended purpose, will ensure public safety, and will comply with applicable laws, regulations, agreements, permits, codes, and standards. Projects shall be engineered by a qualified party. Systems must be engineered as a complete, integrated system with matched components. The engineering must be comprehensive, including site selection, system and component selection, conversion system component and selection, design of the local collection grid, interconnection equipment selection, and system monitoring equipment. Systems must be constructed by a qualified party.

(1) Provide a concise but complete description of the hydropower project, including location of the project, resource characteristics, system specifications, electric power system interconnection equipment and project monitoring equipment. Identify possible vendors and models of major system components. Provide the expected system energy production on a monthly and annual basis.

(2) Describe the project site and address issues such as site access, proximity to the electrical grid, environmental concerns with emphasis on land use, air quality, water quality, habitat fragmentation, visibility, noise, construction, and installation issues. Identify any unique construction and installation issues.

(e) *Project development schedule.* Identify each significant task, its beginning and end, and its relationship to the time needed to initiate and carry the project through startup and shakedown. Provide a detailed description of the project timeline, including resource assessment, system and site design, permits and agreements, equipment procurement, and system installation from excavation through startup and shakedown.

(f) *Project economic assessment.* Provide a study that describes the costs and revenues of the proposed project to demonstrate the financial performance of the proposed project. Provide a detailed analysis and description of project costs, including project management, resource assessment, project design, project permitting, land agreements, equipment, site preparation, system installation, startup and shakedown, warranties, insurance, financing, professional services, and operations and maintenance costs. Provide a detailed description of applicable investment incentives, productivity incentives, loans, and grants. Provide a detailed analysis and description of annual project revenues, including electricity sales, production tax credits, revenues from green tags, and any other production incentive programs throughout the life of the project. Provide a description of planned contingency fees or reserve funds to be used for unexpected large component replacement or repairs and for low productivity periods. In addition, provide other information necessary to assess the project's cost effectiveness.

(g) *Equipment procurement.* Demonstrate that equipment required by the system is available and can be procured and delivered within the proposed project development schedule. Hydropower systems may be constructed of components manufactured in more than one location. Provide a description of any unique equipment procurement issues such as scheduling and timing of component manufacture and delivery, ordering, warranties, shipping, receiving, and on-site storage or inventory. Provide a detailed description of equipment certification. Identify all the major equipment that is proprietary and justify how this unique equipment is needed to meet the requirements of the proposed design. Include a statement from the applicant certifying that ''open and free'' competition will be used for the procurement of project components in a manner consistent with the requirements of 7 CFR part 3015 of this title.

(h) *Equipment installation.* Describe fully the management of and plan for site development and system installation, provide details regarding the scheduling of major installation equipment, including cranes, barges or other devices, needed for project construction, and provide a description of the startup and shakedown specifications and process and the conditions required for startup and shakedown for each equipment item individually and for the system as a whole. Include a statement from the applicant certifying that equipment installation will be made in accordance with all applicable safety and work rules.

(i) *Operations and maintenance.* Identify the operations and maintenance requirements of the system necessary for the system to operate as designed over the design life. The application must:

(1) Ensure that systems must have at least a 3-year warranty for equipment. Provide information regarding turbine warranties and availability of spare parts;

(2) Describe the routine operations and maintenance requirements of the proposed project, including maintenance schedules for the mechanical and electrical systems and system monitoring and control requirements;

(3) Provide information that supports expected design life of the system and timing of major component replacement or rebuilds;

(4) Provide and discuss the risk management plan for handling large, potential failures of major components such as the turbine gearbox or rotor. Include in the discussion, costs and labor associated with the operation and maintenance of the system, and plans for in-sourcing or out-sourcing;

(5) Describe opportunities for technology transfer for long-term project operations and maintenance by a local entity or owner/operator; and

(6) For owner maintained portions of the system, describe any unique knowledge, skills, or abilities needed for service operations or maintenance.

(j) *Dismantling and disposal of project components.* Describe a plan for dismantling and disposing of project components and associated wastes at the end of their useful lives. Describe the budget for and any unique concerns associated with the dismantling and disposal of project components and their wastes.

Appendix B—Renewable Energy System Feasibility Study

Elements in an acceptable feasibility study include, but are not necessarily limited to, the following elements:

- Executive Summary
- Economic Feasibility
- Market Feasibility
- Technical Feasibility (including the appropriate technical report)
- Financial Feasibility
- Management Feasibility
- Qualifications

As noted above, both a technical report for the project and an economic analysis of the project are required as part of the feasibility study. The technical report to be provided must conform to that required under 7 CFR part 4280, as applicable or, if the renewable energy system is a hydropower project, under this notice. The following paragraphs describe the contents that each of section that the feasibility study must contain, as applicable.

Executive Summary. Provide an introduction and overview of the project. In the overview, describe the nature and scope of the proposed project, including purpose, project location, design features, capacity, and estimated total capital cost. Include a summary of each of the elements of the feasibility study, including:

- Economic feasibility determinations.
- Market feasibility determinations.
- Technical feasibility determinations.
- Financial feasibility determinations.
- Management feasibility determinations.

In addition, include a section on recommendations for implementation of the proposed project.

Economic Feasibility. Provide information regarding project site; the availability of trained or trainable labor; and the availability of infrastructure, including utilities, and rail, air and road service to the site. Discuss feedstock source management, including feedstock collection, pre-treatment, transportation, and storage, and provide estimates of feedstock volumes and costs. Discuss the proposed project's potential impacts on existing manufacturing plants or other facilities that use similar feedstock if the proposed technology is adopted. Provide projected impacts of the proposed project on resource conservation, public health, and the environment. Provide an overall economic impact of the project including any additional markets created (e.g., for agricultural and forestry products and agricultural waste material) and potential for rural economic development. Provide feasibility/plans of project to work with producer associations or cooperatives including estimated amount of annual feedstock and biofuel and byproduct dollars from producer associations and cooperatives.

Market Feasibility. Provide information on the sales organization and management. Discuss the nature and extent of market and market area and provide marketing plans for sale of projected output, including both the principle products and the by-products. Discuss the extent of competition including other similar facilities in the market area. Provide projected total supply and projected competitive demand of raw materials. Describe the procurement plan, including projected procurement costs and the form of commitment of raw materials (marketing agreements, etc.). Identify commitments from customers or brokers for both the principle products and the by-products. Discuss all risks related to the industry, including industry status.

Technical Feasibility. The technical feasibility report shall be based upon verifiable data and contain sufficient information and analysis so that a determination may be made on the technical feasibility of achieving the levels of income or production that are projected in the financial statements. The Project engineer or architect is considered an independent party provided neither the principals of the firm nor any individual of the firm who participates in the technical feasibility report has a financial interest in the project. If no other individual or firm with the expertise necessary to make such a determination is reasonably available to perform the function, an individual or firm that is not independent may be used.

Identify any constraints or limitations in the financial projections and any other facility or design-related factors that might affect the success of the enterprise. Identify and estimate project operation and development costs and specify the level of accuracy of these estimates and the assumptions on which these estimates have been based.

Discuss all risks related to construction of the project and regulation and governmental action as they affect the technical feasibility of the project.

Financial Feasibility. Discuss the reliability of the financial projections and assumptions on which the financial statements are based including all sources of project capital both private and public, such as Federal funds. Provide three years (minimum) projected Balance Sheets and Income Statements and cash flow projections for the life of the project. Discuss the ability of the business to achieve the projected income and cash flow. Provide an assessment of the cost accounting system. Discuss the availability of short-term credit or other means to meet seasonable business costs and the adequacy of raw materials and supplies. Provide a sensitivity analysis, including feedstock and energy costs. Discuss all risks related to the project, borrower financing plan, the operational units, and tax issues.

Management Feasibility. Discuss the continuity and adequacy of management. Identify borrower and/or management's previous experience concerning the receipt of federal financial assistance, including amount of funding, date received, purpose, and outcome. Discuss all risks related to the borrower as a company (e.g., borrower is at the Development-Stage) and conflicts of interest, including appearances of conflicts of interest.

Qualifications. Provide a resume or statement of qualifications of the author of the feasibility study, including prior experience.

Appendix C—Grant Agreement for Renewable Energy System Feasibility Studies

This GRANT AGREEMENT is a contract for receipt of grant funds to conduct feasibility studies for renewable energy system projects under the Rural Energy for America program, Title IX, Section 9001 of the Food, Conservation, and Energy Act of 2008,'' (Pub. L. 110–234) between the Grantee and the United States of America acting through Rural Development, Department of Agriculture (Grantor). All references herein to ''Project'' refer to renewable energy system feasibility study project identified in the work plan submitted with the application. Should actual project costs be lower than projected in the work plan, the final amount of grant may be adjusted.

(1) Assurance Agreement

Grantee assures the Grantor that Grantee is in compliance with and will comply in the course of the Agreement with all applicable laws, regulations, Executive Orders, and other generally applicable requirements, including those contained in the Departmental regulations as codified in 7 CFR parts 3000 through 3099, including but not necessarily limited to 7 CFR parts 3015 and successor regulations to these parts, which are incorporated into this Agreement by reference, any Notices relating to this program published in the **Federal Register**, and other applicable statutory provisions.

Any application submitted by the Grantee for this grant, including any attachments or amendments, is incorporated and included as part of this Agreement. Any changes to these documents or this Agreement must be approved in writing by the Grantor.

In addition to any other rights, the Grantor may terminate the grant in whole, or in part, at any time before the date of completion, whenever it is determined that the Grantee has failed to comply with the conditions of this Agreement.

(2) Use of Grant Funds

Grantee will use grant funds and leveraged funds only for the purposes and activities specified in the application approved by the Grantor including the approved budget. Budget and approved use of funds are as further described in the Grantor Letter of Conditions and amendments or supplements thereto. Any uses not provided for in the approved budget must be approved in writing by the Grantor.

(3) Civil Rights Compliance

Grantee will comply with Executive Order 12898, Title VI of the Civil Rights Act of 1964, and Section 504 of the Rehabilitation Act of 1973. This shall include collection and maintenance of data on the race, sex, disability, faith based (if applicable) and national origin of the Grantee's membership/ownership and employees. These data must be available to the Grantor in its conduct of Civil Rights Compliance Reviews, which will be conducted prior to grant closing and 3 years later, unless the final disbursement of grant funds has occurred prior to that date.

(4) Financial Management Systems

A. Grantee will provide a Financial Management System in accordance with 7 CFR part 3015, including but not limited to:

(1) Records that identify adequately the source and application of funds for grant-supported activities. Those records shall contain information pertaining to grant awards and authorizations, obligations, unobligated balances, assets, liabilities, outlays, and income;

(2) Effective control over and accountability for all funds, property, and other assets. Grantees shall adequately safeguard all such assets and ensure that they are used solely for authorized purposes;

(3) Accounting records prepared in accordance with generally acceptable accounting principles (GAAP) or with principles that are generally required by commercial agriculture lenders and supported by source documentation; and

(4) Grantee tracking of fund usage and records that show matching funds and grant funds are used in equal proportions. The Grantee will provide verifiable documentation regarding matching funds usage, i.e., bank statements or copies of funding obligations from the matching source.

B. Grantee will retain financial records, supporting documents, statistical records, and all other records pertinent to the grant for a period of at least 3 years after completion of grant activities, except that the records shall be retained beyond the 3-year period if audit findings have not been resolved or if directed by the United States. The Grantor and the Comptroller General of the United States, or any of their duly authorized representatives, shall have access to any books, documents, papers, and records of the Grantee which are pertinent to the grant for the purpose of making audits, examinations, excerpts, and transcripts.

(5) Procurement

Grantee will comply with the applicable procurement requirements of 7 CFR part 3015 regarding standards of conduct, open and free competition, access to contractor records, and equal employment opportunity requirements.

(6) Monitoring and Reporting

A. After grant approval through project completion, the Grantee shall:

1. Constantly monitor performance to ensure that time schedules are being met and projected goals by time periods are being accomplished.

2. Submit semiannual performance reports to the Grantor. Each report shall describe current progress and identify any problems, delays, or adverse conditions, if any, which have affected or will affect attainment of overall project objectives or prevent meeting time frame for completion of the feasibility study within two years. This disclosure shall be accompanied by a statement of the action taken or planned to resolve the situation.

B. Following completion of the feasibility study, Grantee shall submit to the Grantor:

1. The project feasibility study and SF–270, ''Request for Advance or Reimbursement,'' when the feasibility study has been completed; and

2. A final SF–269, ''Financial Status Report'' and a final performance report within 90 days of the completion of the feasibility study. When submitting the final SF–269, Grantee must submit sufficient documentation, including invoices, to allow the Grantor to verify that said project was completed within the total sums available to it, including the grant and matching funds, in accordance with the work plan and any necessary modifications thereof prepared by grantee and approved by the Grantor; and

C. Beginning the first full year after the feasibility study has been completed, Grantee shall report to the Grantor annually for 2 years on the following:

(1) Is the renewable energy system project for which the feasibility study was conducted underway as a result of the feasibility findings? If yes, describe how far along the renewable energy system project is (e.g., financing has been secured, site has been secured, construction contracts are in place, project completed).

(2) Is the renewable energy system project complete? If so, what is the actual amount of energy being produced?

D. *Other reports.* Grantor may request any additional project and/or performance data for the project for which grant funds have been received.

E. *Records access.* Grantee shall after project completion allow Grantor access to the records and performance information obtained under the scope of the project.

(7) Fund Disbursement

Grant funds will be expended on a pro rata basis with matching funds.

A. Grantee may submit requests for reimbursement monthly or more frequently if authorized to do so by the Agency. Ordinarily, Grantor will make payment within 30 days after receipt of a proper request for reimbursement.

B. Grantee shall not request reimbursement for the Federal share of amounts withheld from contractors to ensure satisfactory completion of work until after it makes those payments.

C. Payment shall be made by electronic funds transfer.

D. An SF–270, ''Request for Advance or Reimbursement,'' must be completed by the Grantee and submitted to the Agency at the completion of the feasibility study.

E. Grantor will disburse grant funds to the Grantee in accordance with the above through 90 percent of grant disbursement. Grantor will hold 10 percent of grant funds until Grantee has submitted a feasibility study acceptable to the Grantor.

(8) Use of Remaining Grant Funds

Grant funds not expended within 24 months from date of this agreement after being used for eligible grant purposes will be cancelled by the Agency. Prior to the actual cancellation, the Agency will notify, in writing, the Grantee of the Agency's intent to cancel the remaining funds.

In witness whereof, Grantee has this day authorized and caused this Agreement to be signed in its name and its corporate seal to be hereunto affixed and attested by its duly authorized officers thereunto, and the Grantor has caused this Agreement to be duly executed in its behalf by:

GRANTEE

Name:

Title:

GRANTOR

Date

United States of America Rural Development By:

Name:

Title:

Date

[FR Doc. E9–12178 Filed 5–22–09; 8:45 am]

BILLING CODE 3410–XY–P

DEPARTMENT OF AGRICULTURE

Forest Service

Ouachita-Ozark Resource Advisory Committee

AGENCY: Forest Service, USDA.

ACTION: Meeting notice for the Ouachita-Ozark Resource Advisory Committee under Section 205 of the Secure Rural Schools and Community Self Determination Act of 2000 (Pub. L. 106–393).

SUMMARY: This notice is published in accordance with section 10(a)(2) of the Federal Advisory Committee Act. Meeting notice is hereby given for the Ouachita-Ozark Resource Advisory Committee pursuant to Section 205 of the Secure Rural Schools and Community Self Determination Act of 2000, Public Law 106–393. Topics to be discussed include: general information, proposals, updates on current or completed Title II projects, and next meeting agenda.

DATES: The meeting will be held on June 30, 2009, beginning at 6 p.m. and ending at approximately 9 p.m.

ADDRESSES: The meeting will be held at the Janet Huckabee Arkansas River Valley Nature Center, 8300 Wells Lake Road, Barling, Arkansas.

FOR FURTHER INFORMATION CONTACT: Caroline Mitchell, Committee Coordinator, USDA, Ouachita National Forest, P.O. Box 1270, Hot Springs, AR 71902. (501–321–5318).

SUPPLEMENTARY INFORMATION: The meeting is open to the public. Committee discussion is limited to Forest Service staff, Committee members, and elected officials. However, persons who wish to bring matters to the attention of the Committee may file written statements with the Committee staff before or after the meeting. Individuals wishing to speak or propose agenda items must send their names and proposals to Bill Pell, DFO, P.O. Box 1270, Hot Springs, AR 71902.

Dated: May 18, 2009.

Bill Pell,

Designated Federal Official.

[FR Doc. E9–12003 Filed 5–22–09; 8:45 am]

BILLING CODE 3410–52–M

DEPARTMENT OF AGRICULTURE

Forest Service

Notice of Resource Advisory Committee Meeting

AGENCY: North Central Idaho Resource Advisory Committee, Grangeville, Idaho, USDA, Forest Service.

ACTION: Notice of meeting.

SUMMARY: Pursuant to the authorities in the Federal Advisory Committee Act (Pub. L. 92–463) and under the Secure Rural Schools and Community Self-Determination Act of 2000 (Pub. L. 110–343) the Nez Perce and Clearwater National Forests' North Central Idaho Resource Advisory Committee will meet

Thursday, June 25th, 2009 in Orofino, Idaho for a business meeting. The meeting is open to the public.

SUPPLEMENTARY INFORMATION: The business meeting on June 25th will be held at the Clearwater National Forest Supervisor's Office in Orofino, Idaho, beginning at 10 a.m. (PST). Agenda topic will be discussion and approval of potential projects. A public forum will begin at 3:15 p.m. (PST).

FOR FURTHER INFORMATION CONTACT: Laura A. Smith, Public Affairs Officer and Designated Federal Officer, at (208) 983–5143.

Dated: May 18, 2008.

Thomas K. Reilly,

Forest Supervisor.

[FR Doc. E9–12038 Filed 5–22–09; 8:45 am]

BILLING CODE 3410–11–M

DEPARTMENT OF COMMERCE

[Docket No. 090520919–9919–01]

RIN 0648-XP46

National Environmental Policy Act—Proposed Categorical Exclusions

AGENCY: U.S. Department of Commerce.

ACTION: Notice, request for comments.

SUMMARY: The U.S. Department of Commerce (DOC) publishes this notice to request public comments on proposed categorical exclusions of actions that the agency has determined do not individually or cumulatively have a significant effect on the human environment and, thus, should be categorically excluded from the requirement to prepare an environmental assessment or environmental impact statement under the National Environmental Policy Act, 42 U.S.C. 4321 *et seq.* (NEPA).

DATES: Comments on the proposed list of categorical exclusions must be received by June 15, 2009 to ensure consideration. Late comments will be considered to the extent practicable.

ADDRESSES: The ''Draft Department of Commerce Administrative Record'' for the proposed categorical exclusions is available at: *http://www.nepa.noaa.gov/procedures.html* under ''Draft Department of Commerce Administrative Record for the proposed categorical exclusions''. All comments should be addressed to Office of Program Planning and Integration, National Oceanic and Atmospheric Administration, Attn.: Steve Kokkinakis, SSMC3—Room 15723, 1315 East-West Highway, Silver Spring, Maryland 20910. Comments may be sent by mail or hand-delivered to the above-listed address Monday—Friday between the hours of 9:00 a.m. and 4:30 p.m. Comments may also be sent by electronic mail to the following internet address: *Strategic.planning@noaa.gov*.

FOR FURTHER INFORMATION CONTACT: Written requests for a hard copy of the ''Draft Department of Commerce Administrative Record'' for the proposed categorical exclusions should be submitted to: Steve Kokkinakis, National Oceanic and Atmospheric Administration, Office of Program Planning & Integration, SSMC3, Room 15723, 1315 East-West Highway, Silver Spring, MD 20910.

SUPPLEMENTARY INFORMATION:

I. National Environmental Policy Act

NEPA requires that Federal agencies prepare environmental impact statements for major Federal actions that may ''significantly affect the quality of the human environment.'' NEPA requirements apply to any federal project, decision, or action, including grants that might have a significant impact on the quality of the human environment. NEPA also established the Council on Environmental Quality (CEQ), which issued regulations implementing the procedural provisions of NEPA. Among other considerations, the CEQ regulations require Federal agencies to adopt their own implementing procedures to supplement the Council's regulations, and to establish and use ''categorical exclusions'' to define categories of actions that do not individually or cumulatively have a significant effect on the human environment. These particular actions, therefore, do not require preparation of an environmental assessment or environmental impact statement as required by NEPA.

DOC consists of thirteen operating units with diverse and often highly technical portfolios that—together—promote job creation and improved living standards for all Americans by creating an infrastructure that promotes economic growth, technological competitiveness, and sustainable development domestically and abroad for all Americans. Among its tasks are: 1. Provide the information and tools to maximize U.S. competitiveness and enable economic growth for American industries, workers, and consumers; 2 Foster science and technological leadership by protecting intellectual property, enhancing technical standards and advancing measurement science; and 3. Observe, protect and manage the Earth's resources to promote environmental stewardship.

DOC does not currently have any Department-wide categorical exclusions (CEs). Only two operating units within DOC have existing CEs—the National Oceanic and Atmospheric Administration (NOAA) and the Economic Development Administration (EDA)—but they are not available for use by other DOC operating units. The need for Department-wide CEs was identified during recent efforts to standardize policy and procedures for all operating unit grant and cooperative agreement programs. This notice targets that effort. DOC is requesting public comment on the following proposed CEs (as well as the administrative record supporting each exclusion) before making them available for use by all of its operating units.

II. Development Process for Establishing Department-wide CEs

The list of DOC CEs was compiled through an inter-departmental effort that included participation from the National Institute of Standards and Technology (NIST), National Telecommunication and Information Administration (NTIA), EDA, NOAA, the Office of General Counsel and the Department's Energy, Safety and Environment Division. Representatives from these organizations comprised the review panel responsible for determining appropriate CEs for the DOC.

The CEs have been approved by the DOC Office of General Counsel and the designated Senior Agency Official for NEPA.

Each proposed CE was reviewed and deliberated in concept, coverage, applicability, and wording. The review panel carefully examined the portion of the administrative record associated with each CE to ensure that the proposed exclusion fulfilled the goal of balancing increased administrative efficiency with avoidance of misinterpretations and misapplications of exclusionary language that could lead to non-compliance with NEPA requirements. Having determined that each proposed CE met these objectives, the review panel ultimately concluded that the actions contemplated by these exclusions encompassed activities that have no inherent potential for significant environmental impacts.

The panel's conclusions were further supported by the determinations made by other Federal agencies that had established CEs for activities similar in nature, scope and impact to those contemplated by DOC. The review panel determined from their experience in or on behalf of other Federal agencies that the characteristics of the activities in

DOC were no different than those performed by other Federal agencies. Accordingly, through a deliberative process, the review panel determined that the proposed categorical exclusions encompassed activities that inherently did not have individual or cumulative significant impact on the human environment.

Notwithstanding these conclusions, the review panel noted that all projects involving a major federal action will be subject to scoring on the ''Departmental NEPA Checklist''. Any project that obtains a ''YES'' answer in any category is not permitted to use the CE and will be required to prepare an Environmental Assessment (EA) or an Environmental Impact Statement (EIS). Moreover, the National Historic Preservation Act requirements, if appropriate, still apply to all projects. The use of these CEs does not constitute a release from Section 106 consultation requirements.

III. Proposed Department-wide Categorical Exclusions

A–1 Minor renovations and additions to buildings, roads, airfields, grounds, equipment, and other facilities that do not result in a change in the functional use of the real property (e.g. realigning interior spaces of an existing building, adding a small storage shed to an existing building, retrofitting for energy conservation, or installing a small antenna on an already existing antenna tower that does not cause the total height to exceed 200 feet and where the FCC would not require an environmental assessment or environmental impact statement for the installation).

This categorical exclusion is supported by long-standing categorical exclusions and administrative records. In particular, the review panel identified the legacy categorical exclusions and Environmental Assessments from the U.S. Department of Agriculture, Federal Emergency Management Agency, Federal Aviation Administration, U.S. Coast Guard, the U.S. Air Force, Immigration and Naturalization Services. Further, the review panel found that Environmental Assessments of a similar nature, scope, and intensity were performed at EDA, NOAA, U.S. Department of Agriculture, Federal Law Enforcement Training Center and the U.S. Border Patrol without significant environmental impacts.

A–2 New construction upon or improvement of land where all of the following conditions are met:

(a) The site is in a developed area and/or a previously disturbed site,

(b) The structure and proposed use are compatible with applicable Federal, tribal, state, and local planning and zoning standards and consistent with federally approved state coastal management programs,

(c) The proposed use will not substantially increase the number of motor vehicles at the facility or in the area,

(d) The site and scale of construction or improvement are consistent with those of existing, adjacent, or nearby buildings, and,

(e) The construction or improvement will not result in uses that exceed existing support infrastructure capacities (roads, sewer, water, parking, etc.).

DOC is not a major land managing agency in the Federal government. Department activities involving new construction or improvements of land typically involve single buildings and supporting infrastructure in a single locality. Any potential for environmental impacts would be of a small scale and confined to more localized impacts.

The review panel identified an internal Departmental EA from EDA that resulted in a Finding of No Significant Impact and legacy categorical exclusions and Findings of No Significant Impact from the U.S. Coast Guard, Federal Emergency Management Agency, U.S. Navy, and the U.S. Border Patrol. EDA issues construction grants to stimulate economic development. Both NOAA and the U.S. Coast Guard manage a large number of facilities in sensitive aquatic environments along all maritime coasts and several rivers. The National Aeronautics and Space Administration has a large number of specialty buildings used to help develop and promote the nation's space program. Legacy categorical exclusions from the Federal Emergency Management Agency include public assistance programs that could be implemented in any part of the United States to assist in preparing and recovering from a disaster. Additionally, legacy categorical exclusions from the U.S. Navy allow minor construction under circumstances identical to those proposed under this DOC categorical exclusion. The U.S. Border Patrol brought a legacy of environmental assessments and findings of no significant impact for its land based activities. Based upon this extensive history of environmental analyses and the experience of its members, the review panel found that actions of a similar nature, scope, and intensity were performed throughout the Federal government without significant environmental impacts.

Since new construction or improvements on land could involve numerous considerations, the review panel took great care to establish limiting provisions to avoid the potential for significant impacts to the human environment. The following limiting provisions were established to both conform to the evidence presented in the administrative record, to clarify meaning of those limiting provisions found in the administrative record, or to add to or modify limitations found in the record based on the experience of the review panel members to further avoid the potential for significant impacts to the human environment:

(a) The site is in a developed area and/or a previously disturbed site,

(b) The structure and proposed use are compatible with applicable Federal, tribal, state, and local planning and zoning standards and consistent with federally approved state coastal management programs (pursuant to the Coastal Zone Management Act);

(c) The proposed use will not substantially increase the number of motor vehicles at the facility or in the area;

(d) The site and scale of construction or improvement are consistent with those of existing, adjacent, or nearby buildings; and

(e) The construction or improvement will not result in uses that exceed existing support infrastructure capacities (roads, sewer, water, parking, etc.)

As a result of all of these limitations, the review panel determined that this categorical exclusion contemplated activities that would inherently have no potential for significant impacts to the human environment.

The review panel defined this categorical exclusion to be sufficiently related to actions that may involve one or more extraordinary circumstances. To ensure that only those actions having negligible impacts on the human environment are contemplated by this categorical exclusion, the review panel proposed that a Record of Environmental Consideration be prepared to document the determination whether the action is either appropriately categorically excluded or whether it requires further analysis through an EA or EIS process.

A–3 Software development, data analysis, or testing, including but not limited to computer modeling in existing facilities.

Research, development, testing, and evaluation activities or laboratory operations contemplated by this categorical exclusion are those that would be undertaken within facilities that are operated under stringent requirements designed to protect the quality of the human environment. As exemplified by documents in the administrative record, these requirements include strict operating procedures governing laboratory operations and personnel responsibilities. Because of these controls, these types of laboratory activities have no potential for significant environmental impacts. Further, the Panel found that actions of a similar nature, scope, and intensity were performed in laboratories throughout the Federal government.

This CE is supported by long-standing categorical exclusions and administrative records. In particular, the review panel identified legacy categorical exclusions from Federal Emergency Management Agency, U.S. Department of Agriculture, U.S. Department of Energy, the U.S. Department of Interior, and the U.S. Navy. Additionally, the review panel identified EAs that resulted in Findings of No Significant Impact from NOAA and the National Aeronautics and Science Administration.

A–4 Siting/construction/operation of microwave/radio communication towers less than 200 feet in height without guy wires on previously disturbed ground.

DOC, through NTIA is involved in issuing grants for siting, construction, operation, and maintenance, communications systems and similar electronic equipment. These types of electronic equipment are essential to support the nationwide telecommunications network.

This CE is supported by Findings of No Significant Impact on the recently completed Programmatic EA for NTIA and on EAs from the U.S. Department of Energy. Furthermore, this CE is supported by long-standing categorical exclusions from the Federal Emergency Management Agency.

A–5 Retrofit/upgrade existing microwave/radio communication towers that do not require ground disturbance.

This CE is supported by the recently completed Programmatic EA for NTIA with a Finding of No Significant Impact and an EA for the National Aeronautics and Space Administration, also with a Finding of No Significant Impact.

A–6 Adding fiber optic cable to transmission structures or burying fiber optic cable in existing transmission line rights-of-way.

This CE is supported by a long-standing categorical exclusion with the Department of Energy and Findings of No Significant Impact on Environmental Assessments prepared for the Bureau of Land Management, Vandenberg Air Force Base, the US Park Service, and the Tennessee Valley Authority.

A–7 Acquisition, installation, operation, and removal of communications systems, data processing equipment, and similar electronic equipment.

This CE is supported by a legacy categorical exclusion from the U.S. Department of Energy and Findings of No Significant Impact on several Description Memorandums from the U.S. Department of Energy.

A–8 Planning activities and classroom-based training and classroom-based exercises using existing conference rooms and training facilities.

This CE is supported by a long-standing categorical exclusion with the Department of Energy and a Finding of No Significant Impact on an Environmental Assessment from the recently completed Programmatic EA for NTIA.

A–9 Purchase of mobile and portable equipment and infrastructure which is stored in previously existing structures or facilities.

This CE is supported by a long-standing categorical exclusion with the U.S. Coast Guard and a Finding of No Significant Impact on an EA from the recently completed Programmatic EA for NTIA.

A–10 Siting, construction (or modification), and operation of support buildings and support structures (including, but not limited to, trailers and prefabricated buildings) within or contiguous to an already developed area (where active utilities and currently used roads are readily accessible).

This CE is supported by a long-standing categorical exclusion with the U.S. Department of Energy and two Memorandum for File for relevant projects and their supporting documentation that indicated insignificant impacts, also with the U.S. Department of Energy.

A–11 Personnel, fiscal, management, and administrative activities, such as recruiting, processing, paying, recordkeeping, resource management, budgeting, personnel actions, and travel.

The actions contemplated by this CE are a variety of administrative activities that have no inherent potential for significant environmental impacts. This CE is supported by long-standing CEs from the U.S. Coast Guard, U.S. Navy, Federal Emergency Management Agency, U.S. Air Force, U.S. Army, and the U.S. Department of the Interior. Further, the Panel found that actions of a similar nature, scope, and intensity were performed throughout the Federal government without significant environmental impacts.

The public is invited to submit comments on both the ''Draft Department of Commerce Administrative Record'' for the proposed CEs, and the CEs listed above. See the ADDRESSES for instructions on submitting comments. The ''Draft Department of Commerce Administrative Record'' for the proposed CEs is available at *http://www.nepa.noaa.gov/procedures.html* under ''Draft Department of Commerce Administrative Record for the proposed categorical exclusions''. In addition, hard copies may be obtained by contacting Steve Kokkinakis, as provided above.

Paperwork Reduction Act

This notice requests public comments on proposed Department-wide CEs and does not contain collection-of-information requirements subject to the Paperwork Reduction Act (PRA) of 1995 (44 U.S.C. 3501 *et seq.*). Notwithstanding any other provision of law, no person is required to, nor shall a person be subject to a penalty for failure to comply with, a collection of information subject to the requirements of the PRA unless that collection of information displays a currently valid OMB control number.

A Paperwork package for the associated ''Departmental NEPA Checklist'' referenced in Section II of the Supplementary Information has been submitted to the Office of Management and Budget (OMB) for review and approval. A Notice of Action in the Federal Register at the conclusion of OMB's review of the information collection.

Dated: May 21, 2009.

Paul N. Doremus,

NOAA NEPA Coordinator, Office of Program Planning and Integration.

[FR Doc. E9–12295 Filed 5–21–09; 4:15 pm]

BILLING CODE 3510–12–S

DEPARTMENT OF COMMERCE

Bureau of Industry and Security

Action Affecting Export Privileges; Matthew Ayadpoor In the Matter of: Matthew Ayadpoor, 9700 Mayview Court, Oklahoma City, OK, 73159; Respondent; Order Relating To Matthew Ayadpoor

The Bureau of Industry and Security, U.S. Department of Commerce (''BIS'') has notified Matthew Ayadpoor (''Ayadpoor''), of its intention to initiate an administrative proceeding against Ayadpoor pursuant to Section 766.3 of the Export Administration Regulations (the ''Regulations''),[1] and Section 13(c) of the Export Administration Act of 1979, as amended (the ''Act''),[2] through the issuance of a proposed charging letter to Ayadpoor that alleged that he committed four violations of the Regulations. Specifically, these charges are:

Charge 1 15 CFR 764.2(c)—Solicitation and Attempt

On or about June 2, 2004, Ayadpoor engaged in conduct prohibited by the Regulations by attempting to have piston-type differential pressure gauges, which is subject to the Regulations and classified as EAR99, exported to Iran without the required U.S. Government authorization. Specifically, Ayadpoor ordered a freight forwarding company to export the gauges to Iran via the United Arab Emirates (''UAE''). Pursuant to Section 560.204 of the Iranian Transactions Regulations maintained by the Department of the Treasury's Office of Foreign Assets Control (''OFAC''), an export to a third country intended for transshipment to Iran is a transaction that requires OFAC authorization. Pursuant to Section 746.7 of the Regulations, no person may engage in the exportation of an item subject to both the Regulations and the Iranian Transactions Regulations without authorization from OFAC. No OFAC authorization was obtained for the export described herein. In engaging in the activity described herein, Ayadpoor committed one violation of Section 764.2(c) of the Regulations.

Charge 2 15 CFR 764.2(e)—Acting with Knowledge of a Violation

In connection with charge one above, on or about June 4, 2004, Ayadpoor violated the Regulations by ordering the export of items subject to the Regulations from the United States with knowledge that a violation of the Regulations would occur in connection with the item. Specifically, Ayadpoor attempted to export items subject to the Regulations and the Iranian Transactions Regulations, with knowledge or reason to know that the items would be exported to Iran via the UAE without the required U.S. Government authorization. Ayadpoor had knowledge that U.S. products could not be sold to sanctioned countries, including Iran, a fact he acknowledged to Office of Export Enforcement (''OEE'') special agents. Additionally, Ayadpoor negotiated for the items with persons in Iran, knowing that the items would be shipped there via the UAE. In so doing, Ayadpoor committed one violation of Section 764.2(e) of the Regulations.

Charge 3 15 CFR 764.2(g)—Misrepresentation and Concealment of Facts

On or about September 8, 2004, Ayadpoor made a false and/or misleading statement to OEE special agents in the course of an investigation subject to the Regulations. Specifically, Ayadpoor told the agents that he had not participated in any export transactions with the UAE company associated with the June 2004 transaction since that transaction. This was a false statement in that on or about August 31, 2004, Ayadpoor ordered that a second shipment of gauges be exported to the same UAE company. In so doing, Ayadpoor committed one violation of Section 764.2(g) of the Regulations.

Charge 4 15 CFR 764.2(i)—Failure To Comply With Recordkeeping Requirements

On or about September 8, 2004, Ayadpoor failed to comply with the recordkeeping requirements set forth in Section 762.2 of the Regulations. Specifically, Ayadpoor failed to retain export control documents, including waybills, and/or other pertinent documents in connection with its export of gauges, described in Charge 3, above. In so doing, Ayadpoor committed one violation of Section 764.2(i) of the Regulations.

Whereas, BIS and Ayadpoor have entered into a Settlement Agreement pursuant to Section 766.18(a) of the Regulations whereby they agreed to settle this matter in accordance with the terms and conditions set forth therein, and

Whereas, I have approved of the terms of such Settlement Agreement; *It is therefore ordered:*

First, Ayadpoor shall be assessed a civil penalty in the amount of $25,000, the payment of which shall be suspended for a period of one (1) year from the date of entry of the Order, and thereafter shall be waived, provided that during the period of suspension, Ayadpoor has committed no violation of the Act, or any regulation, order, or license issued thereunder.

Second, that for a period of one (1) year from the date of entry of the Order, Ayadpoor, his representatives, assigns or agents (''Denied Person'') may not participate, directly or indirectly, in any way in any transaction involving any commodity, software or technology (hereinafter collectively referred to as ''item'') exported or to be exported from the United States that is subject to the Regulations, or in any other activity subject to the Regulations, including, but not limited to:

A. Applying for, obtaining, or using any license, License Exception, or export control document;

B. Carrying on negotiations concerning, or ordering, buying, receiving, using, selling, delivering, storing, disposing of, forwarding, transporting, financing, or otherwise servicing in any way, any transaction involving any item exported or to be exported from the United States that is subject to the Regulations, or in any other activity subject to the Regulations; or

C. Benefitting in any way from any transaction involving any item exported or to be exported from the United States that is subject to the Regulations, or in any other activity subject to the Regulations.

Third, that no person may, directly or indirectly, do any of the following:

A. Export or reexport to or on behalf of the Denied Person any item subject to the Regulations;

B. Take any action that facilitates the acquisition or attempted acquisition by the Denied Person of the ownership,

[1] The Regulations are currently codified in the Code of Federal Regulations at 15 CFR Parts 730–774 (2009). The violations alleged occurred 2004. The Regulations governing the allegation at issue are found in the 2004 version of the Code of Federal Regulations (15 CFR Parts 730–774 (2004)). The 2009 Regulations govern the procedural aspects of the case.

[2] 50 U.S.C. app. §§ 2401–2420 (2000). Since August 21, 2001, has been in lapse and the President, through Executive Order 13222 of August 17, 2001 (3 CFR 2001 Comp. p. 783 (2002)), which has been extended by successive Presidential Notices, the most recent being that of July 23, 2008 (73 FR 43603 (July 25, 2008)), continues the Regulations in effect under the International Emergency Economic Powers Act (50 U.S.C. 1701–1706 (2000)).

possession, or control of any item subject to the Regulations that has been or will be exported from the United States, including financing or other support activities related to a transaction whereby the Denied Person acquires or attempts to acquire such ownership, possession or control;

C. Take any action to acquire from or to facilitate the acquisition or attempted acquisition from the Denied Person of any item subject to the Regulations that has been exported from the United States;

D. Obtain from the Denied Person in the United States any item subject to the Regulations with knowledge or reason to know that the item will be, or is intended to be, exported from the United States; or

E. Engage in any transaction to service any item subject to the Regulations that has been or will be exported from the United States and which is owned, possessed or controlled by the Denied Person, or service any item, of whatever origin, that is owned, possessed or controlled by the Denied Person if such service involves the use of any item subject to the Regulations that has been or will be exported from the United States. For purposes of this paragraph, servicing means installation, maintenance, repair, modification or testing.

Fourth, that, after notice and opportunity for comment as provided in Section 766.23 of the Regulations, any person, firm, corporation, or business organization related to Ayadpoor by affiliation, ownership, control, or position of responsibility in the conduct of trade or related services may also be made subject to the provisions of this Order.

Fifth, that the proposed charging letter, the Settlement Agreement, and this Order shall be made available to the public.

Sixth, that this Order shall be served on the Denied Person and on BIS, and shall be published in the **Federal Register**.

This Order, which constitutes the final agency action in this matter, is effective immediately.

Entered this 15th day of May, 2009.

Kevin Delli-Colli,

Acting Assistant Secretary of Commerce for Export Enforcement.

[FR Doc. E9–12190 Filed 5–22–09; 8:45 am]

BILLING CODE 3510–DT–P

DEPARTMENT OF COMMERCE

Bureau of Industry and Security

Action Affection Export Privileges: Orion Air S.L.; Syrian Pearl Airlines

In the Matter of:

Orion Air, S.L., Canada Real de Merinas, 7 Edificio 5, 3'A, Eissenhower Business Center, 28042 Madrid, Spain.
Ad. de las Cortes Valencianas no 37, Esc.A Puerta 45 46015 Valencia, Spain.
Syrian Pearl Airlines, Damascus International Airport, Damascus, Syria. Respondents.

Order Temporarily Denying Export Privileges

Pursuant to Section 766.24 of the Export Administration Regulations (''EAR''),[1] the Bureau of Industry and Security (''BIS''), U.S. Department of Commerce, through its Office of Export Enforcement (''OEE''), has requested that I issue an Order temporarily denying, for a period of 180 days, the export privileges under the EAR of:

1. Orion Air, S.L., Canada Real de Merinas, 7 Edificio 5, 3'A, Eissenhower Business Center, 28042 Madrid, Spain and Ad. de las Cortes Valencianas no 37, Esc.A Puerta 45 46015 Valencia, Spain.
2. Syrian Pearl Airlines, Damascus International Airport, Damascus, Syria.

BIS has presented evidence that on or about May 1, 2009, Orion Air re-exported a BAE 146–300 aircraft (tail number EC–JVO) to Syria and specifically to Syrian Pearl Airways without the U.S. Government authorization required by General Order No. 2 of Supplement 1 to Part 736 of the EAR. This re-export took place after Orion Air had been directly informed of the export licensing requirements by the U.S. Government, and thus had actual as well as constructive notice of those licensing requirements, and occurred despite assurances made by Orion Air that it would put the transaction on hold based on the U.S. Government's concerns.

The aircraft is powered with four U.S.-origin engines and also contains a U.S.-origin auxiliary power unit (''APU'') and electronic flight instrumentation system (''EFIS''), all of which are items subject to the EAR. The engines and APU are classified as Export Control Classification Number (''ECCN'') 9A991.d and the EFIS is classified as ECCN 7A994. Because the aircraft contains greater than a 10 percent *de minimis* of U.S.-origin items, a fact Orion Air acknowledged, the aircraft is also subject to the EAR if re-exported to Syria and is classified as ECCN 9A991.b. No license was obtained from BIS for export or re-export of the U.S.-origin parts contained in the aircraft, nor the aircraft itself. BIS has also produced evidence that the re-exported aircraft bears the livery, colors and logos of Syrian Pearl Airlines, a national of Syria, a country group E:1 destination.

Moreover, BIS argues that future violations of the EAR are imminent based on statements by Orion Air to the U.S. Government that Orion Air plans to re-export an additional BAE 146–300 aircraft, currently located in Spain, to Syria and specifically to Syrian Pearl Airlines. This information is corroborated by publically available information in the Syrian press and contained in industry data bases. Based on this evidence, including Orion's recent re-export to Syria in violation of the EAR, it is highly likely that this additional aircraft will be re-exported to Syria contrary to U.S. export control laws.

I find that the evidence presented by BIS demonstrates that a violation of the Regulations is imminent in both time and degree of likelihood. The conduct in this case is deliberate, significant and likely to occur again absent the issuance of a TDO. As such, a TDO is needed to give notice to persons and companies in the United States and abroad that they should cease dealing with the Respondents in export transactions involving items subject to the EAR. Such a TDO is consistent with the public interest to preclude future violations of the EAR.

Accordingly, I find that a TDO naming Orion Air and Syrian Pearl Airlines is necessary, in the public interest, to prevent an imminent violation of the EAR.

This Order is being issued on an *ex parte* basis without a hearing based upon BIS's showing of an imminent violation.

It Is Therefore Ordered:

First, that, Orion Air, S.L., Canada Real de Merinas, 7 Edificio 5, 3'A, Eissenhower Business Center, 28042 Madrid, Spain, and Ad. de las Cortes Valencianas no 37, Esc.A Puerta 4546015 Valencia, Spain; and Syrian Pearl Airlines, Damascus International Airport, Damascus, Syria. (each a ''Denied Person'' and collectively the ''Denied Persons'') may not, directly or indirectly, participate in any way in any transaction involving any commodity, software or technology (hereinafter collectively referred to as ''item'') exported or to be exported from the United States that is subject to the Export Administration Regulations (''EAR''), or in any other activity subject to the EAR including, but not limited to:

A. Applying for, obtaining, or using any license, license exception, or export control document;

B. Carrying on negotiations concerning, or ordering, buying, receiving, using, selling, delivering, storing, disposing of, forwarding, transporting, financing, or otherwise servicing in any way, any transaction involving any item exported or to be exported from the United States that is subject to the EAR, or in any other activity subject to the EAR; or

C. Benefiting in any way from any transaction involving any item exported or to be exported from the United States that is subject to the EAR, or in any other activity subject to the EAR.

[1] The EAR is currently codified at 15 CFR Parts 730–774 (2009). The EAR are issued under the Export Administration Act of 1979, as amended (50 U.S.C. app. 2401–2420 (2000)) (''EAA''). Since August 21, 2001, the Act has been in lapse and the President, through Executive Order 13222 of August 17, 2001 (3 CFR, 2001 Comp. 783 (2002)), which has been extended by successive presidential notices, the most recent being that of July 23, 2008 (73 FR 43603 (July 25, 2008)), has continued the Regulations in effect under the International Emergency Economic Powers Act (50 U.S.C. 1701–1706 (2000)) (''IEEPA'').

Second, that no person may, directly or indirectly, do any of the following:

A. Export or reexport to or on behalf of any Denied Person any item subject to the EAR;

B. Take any action that facilitates the acquisition or attempted acquisition by any Denied Person of the ownership, possession, or control of any item subject to the EAR that has been or will be exported from the United States, including financing or other support activities related to a transaction whereby any Denied Person acquires or attempts to acquire such ownership, possession or control;

C. Take any action to acquire from or to facilitate the acquisition or attempted acquisition from any Denied Person of any item subject to the EAR that has been exported from the United States;

D. Obtain from any Denied Person in the United States any item subject to the EAR with knowledge or reason to know that the item will be, or is intended to be, exported from the United States; or

E. Engage in any transaction to service any item subject to the EAR that has been or will be exported from the United States and which is owned, possessed or controlled by any Denied Person, or service any item, of whatever origin, that is owned, possessed or controlled by any Denied Person if such service involves the use of any item subject to the EAR that has been or will be exported from the United States. For purposes of this paragraph, servicing means installation, maintenance, repair, modification or testing.

Third, that after notice and opportunity for comment as provided in section 766.23 of the EAR, any other person, firm, corporation, or business organization related to any of the Respondents by affiliation, ownership, control, or position of responsibility in the conduct of trade or related services may also be made subject to the provisions of this Order.

Fourth, that this Order does not prohibit any export, reexport, or other transaction subject to the EAR where the only items involved that are subject to the EAR are the foreign-produced direct product of U.S.-origin technology.

In accordance with the provisions of Section 766.24(e) of the EAR, the Respondents may, at any time, appeal this Order by filing a full written statement in support of the appeal with the Office of the Administrative Law Judge, U.S. Coast Guard ALJ Docketing Center, 40 South Gay Street, Baltimore, Maryland 21202–4022.

In accordance with the provisions of Section 766.24(d) of the EAR, BIS may seek renewal of this Order by filing a written request not later than 20 days before the expiration date. The Respondents may oppose a request to renew this Order by filing a written submission with the Assistant Secretary for Export Enforcement, which must be received not later than seven days before the expiration date of the Order.

A copy of this Order shall be served on the Respondents and shall be published in the **Federal Register**.

This Order is effective upon issuance and shall remain in effect for 180 days.

Entered this 7th day of May 2009.

Kevin Delli-Colli,

Acting Assistant Secretary of Commerce for Export Enforcement.

[FR Doc. E9–12046 Filed 5–22–09; 8:45 am]

BILLING CODE 3510–DT–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

Notice Requesting Nominations for the Advisory Committee on Commercial Remote Sensing (ACCRES)

AGENCY: U.S. Department of Commerce, National Oceanic and Atmospheric Administration.

SUMMARY: The Advisory Committee on Commercial Remote Sensing (ACCRES) was constituted to advise the Secretary of Commerce through the Under Secretary of Commerce for Oceans and Atmosphere on matters relating to the U.S. commercial remote sensing industry and NOAA's activities to carry out responsibilities of the Department of Commerce set forth in the Land Remote Sensing Policy Act of 1992 (15 U.S.C. Secs 5621–5625). The Committee is composed of leaders in the commercial space-based remote sensing industry, space-based remote sensing data users, government (federal, state, local), and academia. The Department of Commerce is seeking up to five highly qualified individuals knowledgeable about the commercial space-based remote sensing industry and uses of space-based remote sensing data to serve on the Committee.

DATES: Nominations must be postmarked on or before June 25, 2009.

SUPPLEMENTARY INFORMATION: ACCRES was established by the Secretary of Commerce (Secretary) on May 21, 2002, to advise the Secretary through the Under Secretary of Commerce for Oceans and Atmosphere on relating to the U.S. commercial remote sensing industry and NOAA's activities to carry out responsibilities of the Department of Commerce set forth in the Land Remote Sensing Policy Act of 1992 (15 U.S.C. Secs 5621–5625).

The Committee meets twice a year. Committee members serve in a representative capacity for a term of two years and may serve additional terms, if reappointed. No more than 15 individuals may serve on the Committee. Membership is comprised of highly qualified individuals representing the commercial space-based remote sensing industry, space-based remote sensing data users, government (Federal, State, local), and academia from a balance of geographical regions. Nominations are encouraged from all interested persons and organizations representing interests affected by the U.S. commercial space based remote sensing industry. Nominees must possess demonstrable expertise in a field related to the spaced based commercial remote sensing industry or exploitation of space based commercial remotely sensed data and be able to attend committee meetings that are held usually two times per year. In addition, selected candidates must apply for and obtain a security clearance. Membership is voluntary, and service is without pay.

Each nomination submission should include the proposed committee member's name and organizational affiliation, a cover letter describing the nominee's qualifications and interest in serving on the Committee, a curriculum vitae or resume of nominee, and no more than three supporting letters describing the nominee's qualifications and interest in serving on the Committee. Self-nominations are acceptable. The following contact information should accompany each submission: The nominee's name, address, phone number, fax number, and e-mail address if available.

Nominations should be sent to Director, Commercial Remote Sensing Regulatory Affairs Office, 1335 East West Highway, Room 8260, Silver Spring, Maryland 20910. Nominations must be received by June 25, 2009. The full text of the Committee Charter and its current membership can be viewed at the Agency's Web page at *http://www.accres.noaa.gov/index.html.*

FOR FURTHER INFORMATION CONTACT: ACCRES Administration, NOAA Commercial Remote Sensing Regulatory Affairs Office, 1335 East West Highway, Room 8119, Silver Spring, Maryland 20910; telephone (301) 713–1644, fax (301) 713–0204, e-mail *CRSRA@noaa.gov.*

Mary E. Kicza,

Assistant Administrator for Satellite and Information Services.

[FR Doc. E9–12117 Filed 5–22–09; 8:45 am]

BILLING CODE 3510–HR–P

DEPARTMENT OF COMMERCE

Patent and Trademark Office

Submission for OMB Review; Comment Request

The United States Patent and Trademark Office (USPTO) will submit to the Office of Management and Budget (OMB) for clearance the following proposal for collection of information under the provisions of the Paperwork Reduction Act (44 U.S.C. Chapter 35).

Agency: United States Patent and Trademark Office (USPTO).

Title: National Medal of Technology and Innovation Nomination Application.

Form Number(s): None.

Agency Approval Number: 0651–0060.

Type of Request: Revision of a currently approved collection.

Burden: 1,600 hours.

Number of Respondents: 40 responses.

Avg. Hours per Response: 40 hours. This includes time to gather the necessary information, create the documents, and submit the completed request to the USPTO.

Needs and Uses: The public uses the National Medal of Technology and Innovation Nomination Application to recognize through nomination an individual's or company's extraordinary leadership and innovation in technological achievement. The application must be accompanied by at least six letters of recommendation or support from individuals who have first-hand knowledge of the cited achievement(s).

Affected Public: Business or other for-profit; not-for-profit institutions.

Frequency: On occasion.

Respondent's Obligation: Voluntary.

OMB Desk Officer: Nicholas A. Fraser, e-mail: *Nicholas_A_Fraser@omb.eop.gov* .

Once submitted, the request will be publically available in electronic format through the Information Collection Review page at *http://www.reginfo.gov.*

Paper copies can be obtained by:

• *E-mail: Susan.Fawcett@uspto.gov.* Include ''0651–0060 National Medal of Technology and Innovation Nomination Application copy request'' in the subject line of the message.

• *Fax:* 571–273–0112, marked to the attention of Susan K. Fawcett.

• *Mail:* Susan K. Fawcett, Records Officer, Office of the Chief Information Officer, Administrative Management Group, U.S. Patent and Trademark Office, P.O. Box 1450, Alexandria, VA 22313–1450.

Written comments and recommendations for the proposed information collection should be sent on or before June 25, 2009 to Nicholas A. Fraser, OMB Desk Officer, via e-mail at *Nicholas_A_Fraser@omb.eop.gov* or by fax to (202) 395–5167, marked to the attention of Nicholas A. Fraser.

Susan K. Fawcett,

Records Officer, USPTO, Office of the Chief Information Officer, Administrative Management Group.

[FR Doc. E9–12290 Filed 5–22–09; 8:45 am]

BILLING CODE 3510–16–P

DEPARTMENT OF COMMERCE

Bureau of Industry and Security

[08–B IS–0005]

In the Matter of: Micei International, Respondent; Final Decision and Order

This matter is before me upon a Recommended Decision and Order (''RDO'') of an Administrative Law Judge (''ALJ''), as further described below.

In a charging letter filed on July 1, 2008, and amended on January 9, 2009, the Bureau of Industry and Security (''BIS'') alleged that Respondent Micei International (''Micei'') committed fourteen violations of the Export Administration Regulations (currently codified at 15 CFR Parts 730–774 (2009) (''Regulations'')), issued pursuant to the Export Administration Act of 1979, as amended (50 U.S.C. app. 2401–2420) (the ''EAA'' or ''Act''),1 stemming from its knowing participation in seven export transactions using an individual subject to a Denial Order as an employee or agent to negotiate for and/or purchase items in the United States for export from the United States to Micei in Macedonia. The charges are as follows:

1. Since August 21, 2001, the Act has been in lapse, and the President, through Executive Order 13,222 of August 17, 2001 (3 CFR, 2001 Comp. 783 (2002)), which has been extended by successive Presidential Notices, the most recent being that of July 23, 2008 (73 FR 43,603, July 25, 2008), has continued the Regulations in effect under the International Emergency Economic Powers Act (50 U.S.C. 1701–1707).

Charges 1–7; 15 CFR 764.2(b): Causing, Aiding, Abetting, Inducing and/or Permitting a Violation of a Denial Order

As described in further detail in the attached schedule of violations, which is incorporated herein by reference, on seven occasions between on or about July 2, 2003, and on or about October 8, 2003, Micei caused, aided, abetted, induced and/or permitted acts prohibited by the Regulations, namely, the violations by Yuri Montgomery (''Montgomery'') of a BIS order denying Montgomery's export privileges under Section 766.25 of the Regulations (the ''Denial Order''). Specifically, Micei authorized, requested, and/or arranged for Montgomery to negotiate for and/or make certain purchases for or on behalf of Micei of items subject to the Regulations for export from the United States to Micei in Macedonia. To further facilitate these purchases, Micei also contacted Montgomery and provided information on the items to be ordered and their approximate cost, and identified the vendors from which to order them. With Micei's knowledge and/or permission, Montgomery operated or held himself out as Micei's employee or agent, including indicating in an e-mail to a U.S. supplier that Micei had a U.S. regional office in Seattle, Washington, where Montgomery was located, and that Micei was interested in forming a distributorship relationship with the supplier. That e-mail was copied to Micei's president and signed by Montgomery with ''Micei Int'l Reg[ional] Off[ice].'' As part of these actions, Montgomery carried on negotiations concerning, ordered, bought, sold and/or financed various items that were subject to the Regulations and were exported or to be exported from the United States to Micei in Macedonia, and Montgomery benefitted from these transactions, in violation of the Denial Order.

The Denial Order is dated September 11, 2000, and was published in the **Federal Register** on September 22, 2000 (65 FR 57,313). Under the terms of the Denial Order, Montgomery ''may not directly or indirectly, participate in any way in any transaction involving any [item] exported or to be exported from the United States, that is subject to the Regulations, or in any other activity subject to the Regulations, including [c]arrying on negotiations concerning, or ordering, buying, receiving, using, selling, delivering, storing, disposing of, forwarding, transporting, financing, or otherwise servicing in any way, any transaction involving any item exported or to be exported from the United States that is subject to the Regulations, or in any other activity subject to the Regulations; or * * * [b]enefitting in any way from any transaction involving any item exported or to be exported from the United States that is subject to the Regulations, or in any other activity subject to the Regulations.'' The Denial Order is effective until January 22, 2009, and continued in force at the time of the aforementioned actions. In so doing, Micei committed seven violations of Section 764.2(b) of the Regulations.

Charges 8–14; 15 CFR 764.2(e): Acting with Knowledge of a Violation

As described in further detail in the attached schedule of violations, which is incorporated herein by reference, on seven occasions between on or about July 2, 2003 and on or about October 8, 2003, Micei ordered, bought, sold, used and/or financed various items subject to the Regulations with knowledge that violations of an order issued under the Regulations had occurred, was about to occur, or was intended to occur in connection with the items, namely, the violations by Yuri Montgomery (''Montgomery'') of a BIS order denying Montgomery's export privileges under Section 766.25 of the Regulations (the ''Denial Order''). Operating as Micei's employee or agent or otherwise for or on its behalf during these transactions, Montgomery carried on negotiations concerning, ordered, bought, sold and/or financed various items that were subject to the Regulations and were exported or to be exported from the United States to Micei in Macedonia, and also benefitted from these transactions, in violation of the Denial Order. The Denial Order is dated September 11, 2000, and was published in the **Federal Register** on September 22, 2000 (65 FR 57,313). At the time of these actions, Montgomery's export privileges were denied by the Denial Order. Micei knew that Montgomery was subject to the Denial Order because, *inter alia,* on November 6 and 13, 2003, Iii Malinkovski, then identified as a vice president of Micei, told BIS Special Agents that he was aware of the Denial Order on Montgomery and that Montgomery was subject to the Denial Order until January 2009. In so doing, Micei committed seven violations of Section 764.2(e) of the Regulations.

January 9, 2009; Amended Charging Letter at 1–2

In sum, Charges 1–7 alleged that on seven occasions between on or about July 2, 2003 and on or about October 8, 2003, Micei caused, aided, abetted and/or induced violations of a BIS denial order in violation of Section 764.2(b); in connection with those same transactions and items, Charges 8–14 allege that, in violation of Section 764.2(e), Micei acted with knowledge that the violations of the denial order had occurred, were about to occur, or were intended to occur.

The Respondent filed a lengthy motion to dismiss on September 17, 2008, which raised several jurisdictional challenges, including whether the Regulations were in effect at the time of the violations and whether the Regulations apply extraterritorially. After briefing on the motion was completed, in an order dated December 22, 2008, the ALJ ruled that a motion to dismiss is not provided for in the Regulations, but gave the Respondent the benefit of the doubt and reviewed the motion as if it were a motion for summary decision, which is provided for by Section 766.8 of the Regulations. ALJ Order Denying Motion To Dismiss; RDO at 4–5. The ALJ ruled that the motion was without merit and did not meet the requirements for summary decision under Section 766.8 of the Regulations, and set a deadline of January 12, 2009 for the Respondent to file an answer. *Id.*

On January 9, 2009, BIS filed an amended Charging Letter that was served by Federal Express, registered mail, fax, and e-mail, which under the Regulations extended Respondent's time to answer arguably until February 12, 2009 (pursuant to the delivery by Federal Express), and certainly no later than February 19, 2009 (pursuant to the registered mail delivery). This amendment included limited additional allegations concerning the same transactions, items, and violations as alleged in the initial Charging Letter 2.

2. The items involved in the transactions were as follows: boots in Charges 1 and 8; firing range clearing devices in Charges 2 and 9; boots in Charges 3 and 10; shoes and remote strobe tubes in Charges 4 and 11; shirts in Charges 5 and 12; a load binder, ratchet strap, binder chain and safety shackle in Charges 6 and 13; and the items in order number 25473620/017 in Charges 7 and 14.

Respondent did not file anything further until February 23, 2009, when it filed not an answer, but what it styled a motion for a more definite statement. BIS filed a motion for a default order on March 24, 2009, arguing that Respondent had not filed an answer within the time provided by the Regulations (and the ALJ's Order Denying Motion To Dismiss), and had waived its right to contest the allegations pursuant to Section 766.7 of the Regulations. Although BIS is not required under Section 766.7 to give notice of its motion for default order, BIS served its motion (and opposition to Respondent's motion for a more definite statement) by Federal Express, fax, and e-mail.

Respondent has not filed an answer to the amended Charging Letter dated January 9, 2009, and did not file an answer to the initial Charging Letter dated July 1, 2008. It also did not respond to BIS's motion for default order.

On April 14, 2009, the ALJ issued the RDO, denying Respondent's motion for a more definite statement and granting BIS's motion for a default order. Even though the ALJ did not specifically state that the Regulations provide for the filing of a motion for a more definite statement, the Regulations do not, in fact, provide for such a motion, just as they do not provide for a motion to dismiss. 15 CFR Part 766; In the Matter of Yuri Montgomery, ALJ Brudzinski's Order Denying Respondent's Motion for More Definite Statement at 6 (March 23, 2009) (''The regulations at 15 CFR Part 766 do not provide for motions for a more definite statement or for hearings thereon.''). Further, the Respondent's motion was frivolous in that the Charging Letter clearly met all of the requirements of Section 766.3 of the Regulations, including setting forth the essential facts about the alleged violations, referring to the specific regulatory and other provisions involved, and giving notice of the available sanctions. 15 CFR 766.3(a). The Respondent's motion for a more definite statement was, in fact, just another vehicle through which Respondent sought to avoid answering the charges, and instead repeated the arguments put forth in its motion to dismiss, which had previously been denied. The ALJ determined that the Respondent ''ha[d] been given several opportunities to participate in the process'' and contest the charges in this matter, but had demonstrated ''a pattern of declining to file an answer.'' RDO at 12.

3. Under the Federal Rules of Civil Procedure, *Federal* courts will only grant such a motion when the complaint is ''so vague or ambiguous that a party cannot reasonably prepare a response.'' Fed. R. Civ. P. 12(e); *Brown* v. *Aramark Corp.,* 591 F. Supp. 2d 68 at 76 n. 5 (D.D.C. 2008) (the basis for granting a motion for a more definite statement under Rule 12(e) is ''unintelligibility, not mere lack of detail'').

Pursuant to Section 766.7 of the Regulations, the ALJ found the facts to be as alleged in the Charging Letter and concluded that Micei committed seven violations of 764.2(b) when it caused, aided and abetted Montgomery's violations of the Denial Order as alleged in Charges 1–7, and committed seven violations of 764.2(e) when, as alleged in Charges 8–14, it acted with knowledge of those violations of the Denial Order. The ALJ also recommended that Micei be assessed a monetary penalty of $126,000 and a denial of its export privileges for five years, given, *inter alia,* that Micei deliberately participated in multiple export transactions of items from the United States to Macedonia involving violations of a BIS Denial Order, and given its failure to contest the charged violations or meet the deadlines provided in the Regulations and orders issued in this matter.

The RDO, together with the entire record in this case, has been referred to me for final action under § 766.22 of the Regulations. I find that the record supports the ALJ's findings of fact and conclusions of law.

In doing so, I have determined that the ALJ properly found that the items at issue were located in the United States and were exported or (on one occasion) intended to be exported from the United States to Micei in Macedonia. Findings of Fact, RDO at 69. The ALJ also correctly concluded that the items at issue are subject to the Regulations. Conclusions of Law, RDO at 17.

In the Discussion section of the RDO (pages 9–16 of the RDO), the ALJ cited to both Sections 734.3(a)(1) (''all items in the United States'') and 734.3(a)(2) (''all U.S. origin items wherever located''). RDO at 9. In that section, the ALJ also subsequently referred to the items as being ''of U.S. origin.'' RDO at 10, 15. I have not determined as part of this decision whether the items were manufactured in the United States, and thus were ''of U.S. origin,'' and such a determination is not necessary because jurisdiction over the items is established in this matter under Section 734.3(a)(1), given the location of these items in the United States. Indeed, all of the items were purchased, or attempted to be purchased, in the United States for export from the United States to Micei in Macedonia, as found in the RDO. Thus, my determinations are entirely consistent with the allegations contained in the Charging Letter and the findings and conclusions contained in the RDO.

The jurisdictional challenges raised by Respondent have been considered and denied in prior matters, but there is value in repeating the central points. The continuation of the operation and effectiveness of the FAA and its regulations through the issuance of Executive Orders by the President constitutes a valid exercise of authority. *See* Wisconsin Project on *Nuclear Arms Control* v. *U.S. Dep't of Commerce,* 317 F.3d 275, 278–79 (D.C. Cir. 2003), and *Times Publ'g Co.* v. *U.S. Dep't of Commerce,* 235 F.3d 1286, 1290 (11th Cir. 2001)). Therefore, as the ALJ stated, ''the laws and regulations underlying this enforcement action and the corresponding procedural requirements were in full force on the dates of the charged violations and have remained in effect pursuant to the authority exercised by the President.'' Order Denying Motion to Dismiss at 4.

Respondent's arguments challenging the extraterritorial reach of the FAA and the Regulations may be irrelevant in light of the allegations of its substantial contacts with the United States, including those contacts carried out through Montgomery acting, with Micei's knowledge and permission, as Micei's employee or agent. Nevertheless, to the extent that this matter concerns the extraterritorial application of the FAA and the Regulations, the ALJ correctly determined that both apply to persons extraterritorial so long as items subject to the Regulations are involved, and regardless of the person's nationality or locality. RDO at 10; In the Matter of Mahdi, 68 FR 57406 (Oct. 3, 2003)); accord In the Matter of Petrom GmbH International Trade, 70 FR 32743 (June 6, 2005) and In the Matter of Petrochemical Commercial Co. Ltd., 71 FR 23983 (May 6, 2005). The Respondent is therefore subject to the Regulations based on its actions involving items subject to the Regulations that at the least were located in and purchased (or attempted to be purchased) from the United States and then exported from the United States to the Respondent. *United States* v. *McKeeve,* 131 F.3d 1 (1st Cir. 1997) (the First Circuit cited Section 1702(a)(1) when it rejected an extraterritorial challenge to an IEEPA conspiracy conviction brought by a foreign national in the context of a conspiracy involving foreign nationals to export computer equipment to Libya. The computer equipment was stored in Massachusetts and therefore ''unquestionably subject to the jurisdiction of the United States'').

I also find that the penalty recommended by the ALJ based upon his review of the entire record is appropriate, given the nature of the violations, the facts of this case, and the importance of deterring future unauthorized exports or attempted exports. Micei deliberately participated in multiple export transactions of items from the United States to Macedonia involving violations of a BIS Denial Order, and its blatant disregard for U.S. export control laws is further highlighted by its conduct during this enforcement action.

Based on my review of the entire record, I affirm the findings of fact and conclusions of law in the RDO.

Accordingly, it is therefore ordered,

First, that a civil penalty of $126,000.00 is assessed against Micei International, which shall be paid to the U.S. Department of Commerce within (30) thirty days from the date of entry of this Order.

Second, pursuant to the Debt Collection Act of 1982, as amended (31 U.S.C. 370 1–3720E (2000)), the civil penalty owed under this Order accrues interest as more fully described in the attached Notice, and, if payment is not made by the due date specified herein, Micei International will be assessed, in addition to the full amount of the civil penalty and interest, a penalty charge and administrative charge.

Third, for a period of five (5) years from the date that this Order is published in the **Federal Register**, Micei International, Kamnik bb, 1000 Skopje, Republic of Macedonia, its successors or assigns, and when acting for or on behalf of Micei, its representatives, agents, officers or employees (hereinafter collectively referred to as ''Denied Person'') may not participate, directly or indirectly, in any way in any transaction involving any commodity, software or technology (hereinafter collectively referred to as ''item'') exported or to be exported from the United States that is subject to the Regulations, or in any other activity subject to the Regulations, including, but not limited to:

A. Applying for, obtaining, or using any license, License Exception, or export control document;

B. Carrying on negotiations concerning, or ordering, buying, receiving, using, selling, delivering, storing, disposing of, forwarding, transporting, financing, or otherwise servicing in any way, any transaction involving any item exported or to be exported from the United States that is subject to the Regulations, or in any other activity subject to the Regulations; or

C. Benefiting in any way from any transaction involving any item exported or to be exported from the United States that is subject to the Regulations, or in any other activity subject to the Regulations.

Fourth, that no person may, directly or indirectly, do any of the following:

A. Export or reexport to or on behalf of the Denied Person any item subject to the Regulations;

B. Take any action that facilitates the acquisition or attempted acquisition by the Denied Person of the ownership, possession, or control of any item subject to the Regulations that has been or will be exported from the United States, including financing or other support activities related to a transaction whereby the Denied Person acquires or attempts to acquire such ownership, possession or control;

C. Take any action to acquire from or to facilitate the acquisition or attempted acquisition from the Denied Person of any item subject to the Regulations that has been exported from the United States;

D. Obtain from the Denied Person in the United States any item subject to the Regulations with knowledge or reason to know that the item will be, or is intended to be, exported from the United States; or

E. Engage in any transaction to service any item subject to the Regulations that has been or will be exported from the United States and which is owned, possessed or controlled by the Denied Person, or service any item, of whatever origin, that is owned, possessed or controlled by the Denied Person if such service involves the use of any item subject to the Regulations that has been or will be exported from the United States. For purposes of this paragraph, servicing means installation, maintenance, repair, modification or testing.

Fifth, that, after notice and opportunity for comment as provided in § 766.23 of the Regulations, any person, firm, corporation, or business organization related to the Denied Person by affiliation, ownership, control, or position of responsibility in the conduct of trade or related services may also be made subject to the provisions of the Order.

Sixth, that this Order does not prohibit any export, reexport, or other transaction subject to the Regulations where the only items involved that are subject to the Regulations are the foreign-produced direct product of U.S.-origin technology.

Seventh, that the final Decision and Order shall be served on Micei and on BIS and shall be published in the **Federal Register**. In addition, the ALJ's Recommended Decision and Order, except for the section related to the Recommended Order, shall also be published in the **Federal Register**.

This Order, which constitutes the final agency action in this matter, is effective upon publication in the **Federal Register**.

Dated: May 14, 2009.

Daniel Hill,

Acting Under Secretary of Commerce for Industry and Security.

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United States of America, Department of Commerce, Bureau of Industry and Security.

In the Matter of: MICEI International, Respondent.

Docket No.: 08–BIS–0005.

Recommended Decision and Order Granting Motion for Default.

Issued: April 14, 2009.

Issued by: Hon. Michael J. Devine.

I. Summary of Decision

This case arises from Respondent Micei International's (Micei) use of an individual subject to a Denial Order as an employee or agent to negotiate for Respondent Micei and facilitate exports from the United States. The charging letter identifies Yuri Montgomery (''Montgomery''), as the individual involved in transactions with Micei which violate the terms of a previously issued Denial Order in connection with his (Montgomery's) exporting various goods from the United States to Macedonia in 2003. Micei International, Inc. (''Micei'' or ''Respondent''), has been charged causing, aiding, or abetting Montgomery to violate the Denial Order and acting with knowledge of the violation. The Bureau of Industry Security, United States Department of Commerce (''BIS'' or ''Bureau'') has alleged that Micei's conduct in connection with Montgomery violating his Denial Order constitutes fourteen (14) violations of the Export Administration Act of 1979 (''Act'' or ''EAA'') and the Export Administration Regulations (''EAR''). 50 U.S.C. app. 2401–20 (1991), amended by Public Law 106–508, 114 Stat. 2360 (Supp. 2002) (EAA); 15 CFR Parts 730–74 (1997–1999) (EAR or Regulations). Montgomery is not a party to this enforcement action against Micei International.

The EAA and its underlying regulations establish a ''system of controlling exports by balancing national security, foreign policy and domestic supply needs with the interest of encouraging export to enhance * * * the economic well being'' of the United States. *Times Publ'g Co.* v. *United States Dep't of Commerce,* 236 F.3d 1286, 1290 (11th Cir. 2001); *see also* 50 U.S.C. app. 240120.[1]

Here, BIS alleges that Micei committed fourteen (14) violations of the EAR and seeks a denial of the Respondent's export privileges from the United States for a period of five (5) years as well as assessment of $126,000 in civil penalties.

As discussed infra, Micei filed a Motion to Dismiss the charges and various briefs and materials in support of that motion, including a declaration by Iki Malinkovski. However, Micei has not filed an Answer or other appropriate responsive pleadings in this case. After the time for an Answer passed, BIS filed a Motion for Default. This Order finds that Respondent Micei is in default and that the fourteen (14) violations of the EAA and EAR alleged in the Amended Charging Letter are proven by default. Finally, this Order recommends imposing a five (5) year denial of export privileges and a $126,000.00 civil penalty upon Respondent.

II. Background

On July 2, 2008, BIS filed a Charging Letter with the Docketing Center alleging that Micei committed fourteen (14) violations of the Export Administration Regulations (''EAR'') and the Export Administration Act of 1979 (''EAA'').[2]

Specifically, BIS alleges that on seven (7) occasions between on or about July 2, 2003, and on or about October 8, 2003, Micei caused, aided, abetted, and/or induced an Montgomery to violate a BIS Order which denied that individual's export privileges under 15 CFR 766.25. These charges involve alleged illegal exportation of various goods from the United States to Macedonia.

BIS further alleges that these acts created seven (7) additional violations of the EAR because Micei committed them with knowledge that a violation of an order issued under the EAR had occurred, was about to occur, or was intended to occur in connection with the transactions.

On September 17, 2008, Respondent through counsel[3] filed Respondent's

[1] The EAA and all regulations promulgated thereunder expired on August 20, 2001. *See* 50 U.S.C. App. 2419, Three days before its expiration, on August 17, 2001, the President declared the lapse of the EAA constitutes a national emergency. *See* Exec. Order. No. 13222, reprinted in 3 CFR at 783–784, 2001 comp. (2002). Exercising authority under the International Emergency Economic Powers Act (''IEEPA''), 50 U.S.C. 170 1–1706 (2002), the President maintained the effectiveness of the EAA and its underlying regulations throughout the expiration period by issuing Exec. Order. No. 13222 on August 17, 2001. *Id.* The effectiveness of the export control laws and regulations were further extended by successive Notices issued by the President; the most recent being that of July 23, 2008. *See* Notice: Continuation of Emergency Regarding Export Control Regulations, 73 FR 43603 (July, 23, 2008). Courts have held that the continuation of the operation and effectiveness of the EAA and its regulations through the issuance of Executive Orders by the President constitutes a valid exercise of authority. *See* Wisconsin Project on *Nuclear Arms Control* v. *U.S. Dep't of Commerce,* 317 F.3d 275, 278–79 (D.C. Cir. 2003); *Times Publ'g Co.* v. *U.S. Dep't of Commerce,* 236 F.3d 1286, 1290 (11th Cir. 2001).

[2] The EAR and EAA are currently in full force and effect and have been at all relevant times with respect to this case. *See* discussion supra n.1 wherein the history of these laws and regulations is examined.

[3] Note that the attorney initially representing Respondent requested to withdraw and that the

Continued

Motion to Dismiss and Demand for a Hearing on the Motion to Dismiss. With said filing, Respondent submitted a Memorandum of Points and Authorities in support of its Motion to Dismiss wherein Respondent made numerous arguments and included extensive discussion. After prehearing scheduling matters, including various filings, and interim Orders which need not be discussed here, BIS filed its Opposition to Respondent's Motion to Dismiss on November 25, 2008,[4] BIS addressed Respondent's Motion to Dismiss and the arguments and authorities contained therein. On December 16, 2008 Respondent submitted its Reply to BIS's Opposition to Respondent's Motion to Dismiss.[5]

On December 22, 2008, this Court issued an Order denying Respondent's Motion to Dismiss and Demand for Hearing on the Motion to Dismiss. Respondent's demand for a hearing on the Motion to Dismiss was denied because the Regulations do not provide for such a procedural step and because the parties already fully briefed the Court on the Motion to Dismiss, thus rendering a hearing on the matter unnecessary. After extensive briefing by the parties, Respondent's Motion to Dismiss was similarly denied because the Regulations do not provide for this procedural step, it was not sufficient to be a Motion for Summary Decision, and because there was no merit to Respondent's position. At the core of Respondent's argument was an assertion that this Court somehow lacked jurisdiction to adjudicate the case based on a Federal Civil Procedure process for civil lawsuits that does not apply to administrative regulation matters. This argument was rejected with an explanation of BIS's and the Court's jurisdiction along with a brief restatement of how administrative law functions.

Respondent's Motion to Dismiss could have been considered as non responsive and subject to default because it was not in proper form to be considered either as an Answer to the Charges or as a Motion permitted by the regulations. Since Respondent's Motion to Dismiss was not sufficient as an Answer, it was considered and analyzed as if it were a Motion for Summary Decision. The Motion was insufficient as a Motion for Summary Decision as well in that it failed to establish that there was no genuine issue of material fact and that based on the facts Respondent was entitled to judgment as a matter of law. The Motion was denied on December 22, 2008 and a Scheduling Order was issued that directed Respondent to file an Answer by January 12, 2009.

On January 9, 2009, BIS filed a Notice of Amended Charging Letter containing limited additional allegations involving the same charged violation. The amendments asserted additional support for the allegations that Respondent conducted itself with knowledge that a violation of Montgomery's Denial Order would occur. This amendment was allowed by rule because Respondent had yet to file an answer at that time. 15 CFR 766.3(a). An Answer to the Amended Charging Letter was due on February 10, 2009 in keeping with the regulations that require an Answer within 30 days of notice of the amendment to the charges. 15 CFR 766.6(a).

On February 23, 2009, Respondent filed a Motion for a More Definite Statement and Demand for Hearing. This motion repeats much of the argument asserted in the Motion to Dismiss that was denied by the Order of December 22, 2008.

On March 24, 2009, BIS filed a Motion for Default Order and Opposition to Respondent's Motion for a More Definite Statement. BIS sought a civil penalty of $126,000 and a five (5) year denial of export privileges for Micei. On April 1, 2009, BIS filed a Motion to Stay Further Running of the Court's Scheduling Order. As discussed below, Respondent's Motion for a More Definite Statement is denied and BIS's Motion for Default is granted. This Order fully resolves this matter, therefore BIS's Motion to Stay Further Running of the Court's Scheduling Order is moot. Likewise any other Motions pending in this case are moot.

III. Recommended Findings of Fact

In light of the Respondent's failure to file an answer within the time provided, the facts alleged in the Amended Charging Letter are found proven. 15 CFR 766.7(a). The facts found proven include the following:

1. Micei International is a company of Skopje, Macedonia.
2. Micei has a regional office in Seattle, WA.
3. The supplier at issue in this case is a U.S. supplier.
4. Iki Malinkovski was the vice president of Micei at all relevant times.
5. Yuri Montgomery is an individual subject to a BIS Denial Order at all relevant times.
6. The Denial Order regarding Yuri Montgomery dated September 11, 2000, was published in the **Federal Register** on September 22, 2000 (65 FR 57,313), and has been and continued to be effective until January 22, 2009.
7. Under the terms of the Denial Order, Montgomery ''may not directly or indirectly, participate in any way in any transaction involving any [item] exported or to be exported from the United States, that is subject to the Regulations, or in any other activity subject to the Regulations, including [c]arrying on negotiations concerning, or ordering, buying, receiving, using, selling, delivering, storing, disposing of, forwarding, transporting, financing, or otherwise servicing in any way, any transaction involving any item exported or to be exported from the United States that is subject to the regulations, or in any other activity subject to the regulations; or * * * [b]enefiting in any way from the transaction involving any item exported or to be exported from the United States that is subject to the Regulations or in any other activity subject to the Regulations.''
8. On July 2, 2003, Micei authorized, requested, and/or arranged for Montgomery to negotiate for and/or purchase 61 pair of Magnum boots valued at $3,355 for or on behalf of Micei for export from the United States to Micei in Macedonia. On the same day and acting through its employee or agent Montgomery, Micei Ordered, bought, sold, used and/or financed this purchase with knowledge that Montgomery would be violating his Denial Order. Montgomery participated in and benefited from this transaction.
9. On July 18, 2003, Micei authorized, requested, and/or arranged for Montgomery to negotiate for and/or purchase 2 firing range clearing devices

company president step in as a non attorney representative until replacement counsel could be obtained. As noted in the file, the Respondent's counsel was not permitted to withdraw until after the Motion to Dismiss was resolved. On December 11, 2008, Mr. Vasko Tomanovic filed a Notice of Appearance of Respondent's Substitute Counsel. It is unclear whether Mr. Tomanovic is now the sole representative or whether the company president who has been serving as a non attorney representative retains any involvement as a representative. Unless the Court is notified to the contrary, Mr. Tomanovic and the company president will be treated as joint representatives in this case.

[4] Note that BIS's November 25, 2008 filing is a corrected version of a previous filing. For simplicity, BIS's November 25, 2008 filing will be discussed as if it were BIS sole opposition to Respondent's Motion to Dismiss.

[5] A Notice of Filing Corrected Version of Respondent's Reply Memorandum of Points and Authorities in Support of Memorandum to Dismiss was submitted by Vasko Tomanovic on behalf of Respondent Micei on December 18, 2008. This also included a declaration in support of the motion by Iki Malinkovski which contains various asserted ''facts'' regarding the Micei company and its interaction with his Uncle Yuri Montgomery. Since the motion was denied and no responsive Answer or pleading has been filed by Micei, none of the matters asserted in support of the motion will be considered either as admissions or as a basis for Micei to deny or contest the charged violations.

valued at $1,136 for or on behalf of Micei for export from the United States to Micei in Macedonia. On the same day and acting through its employee or agent Montgomery, Micei Ordered, bought, sold, used and/or financed this purchase with knowledge that Montgomery would be violating his Denial Order. Montgomery participated in and benefited from this transaction.

10. On August 5, 2003, Micei authorized, requested, and/or arranged for Montgomery to negotiate for and/or purchase 10,800 pair of boots with an undetermined value for or on behalf of Micei for export from the United States to Micei in Macedonia. On the same day and acting through its employee or agent Montgomery, Micei Ordered, bought, sold, used and/or financed this purchase with knowledge that Montgomery would be violating his Denial Order. Montgomery participated in and benefited from this transaction.

11. On August 5, 2003, Micei authorized, requested, and/or arranged for Montgomery to negotiate for and/or purchase 45 pair of Oxford shoes and 5 remote strobe tubes valued at $2,562 for or on behalf of Micei for export from the United States to Micei in Macedonia. On the same day and acting through its employee or agent Montgomery, Micei Ordered, bought, sold, used and/or financed this purchase with knowledge that Montgomery would be violating his Denial Order. Montgomery participated in and benefited from this transaction.

12. On August 13, 2003, Micei authorized, requested, and/or arranged for Montgomery to negotiate for and/or purchase 150 shirts valued at $1,744 for or on behalf of Micei for export from the United States to Micei in Macedonia. On the same day and acting through its employee or agent Montgomery, Micei Ordered, bought, sold, used and/or financed this purchase with knowledge that Montgomery would be violating his Denial Order. Montgomery participated in and benefited from this transaction.

13. On September 9, 2003, Micei authorized, requested, and/or arranged for Montgomery to negotiate for and/or purchase 2 load binders, 1 ratchet strap, 1 binder chain, and 1 safety shackle for or on behalf of Micei for export from the United States to Micei in Macedonia. On the same day and acting through its employee or agent Montgomery, Micei Ordered, bought, sold, used and/or financed this purchase with knowledge that Montgomery would be violating his Denial Order. Montgomery participated in and benefited from this transaction.

14. On October 8, 2003, Micei authorized, requested, and/or arranged for Montgomery to negotiate for and/or purchase Items in Order # 25473620/017 for or on behalf of Micei for export from the United States to Micei in Macedonia. On the same day and acting through its employee or agent Montgomery, Micei Ordered, bought, sold, used and/or financed this purchase with knowledge that Montgomery would be violating his Denial Order. Montgomery participated in and benefited from this transaction.

15. To further facilitate these purchases, Micei contacted Montgomery and provided information on the items to be ordered and their approximate cost, and identified the vendors from which to order them. With Micei's knowledge and/or permission, Montgomery operated or held himself out as Micei's employee or agent, including indicating in an e-mail to a U.S. supplier that Micei had a U.S. regional office in Seattle, Washington, where Montgomery was located, and that Micei was interested in forming a distributorship relationship with the supplier. That e-mail was copied to Micei's president and signed by Montgomery with ''Micei Int'l Reg[ional] Office].''

IV. Discussion

A. Application of EAR and EAA to Respondent and to Montgomery

Throughout this enforcement proceeding, Micei has repeatedly contended that the Bureau lacks jurisdiction over Micei and the relevant transactions at issue in this case. These arguments are rejected and have been fully discussed in a previous Order. The jurisdictional grounds for this enforcement action are nevertheless briefly outlined below.

The authority delegated by Congress to the President of the United States under the EAA is extensive. The EAA gives the President authority to regulate or prohibit the export of goods, technology, and information ''to the extent necessary to further the foreign policy of the United States or fulfill its international obligation.'' 50 U.S.C. app. 2405(a)(1).

1. BIS Authority Over These Items

The instant case involves various goods supplied to Micei through a U.S. supplier for shipment abroad to Macedonia. Based on the above referenced authority, the Regulations specify that ''all U.S. origin items wherever located'' are subject to the EAR and are therefore ''items * * * over which BIS exercises regulatory jurisdiction under the EAR.'' 15 CFR 734.3(a)(1)–(a)(2). The Regulations further specify that ''item'' simply means ''commodity,'' which is defined as ''[a]ny article, material, or supply.'' 15 CFR 772.1. This case involves the materials noted in the charges as being exported to Macedonia by the action of Micei and its agents or employees, including: Boots, firing range clearing devices, shoes, remote strobe tubes, shirts, load binders, a ratchet strap, a binder chain, a safety shackles, and other items included in order #25473620/017. The various goods at issue in this case are clearly articles, materials, and supplies and are therefore commodities, and thus are ''items'' under the regulations. Since their supplier was located in the U.S., they were of U.S. origin and therefore subject to the EAR, giving BIS regulatory authority.

2. BIS Authority Over Micei and Montgomery

At the time in question, the EAR affirmatively stated that no ''person'' may engage in a variety of prohibited acts. 15 CFR 764.2(b), (e). The EAR defines a person as a ''natural person, including a citizen or national of the United States or of any foreign country; any firm;* * * and any other association or organization whether or not organized for profit.'' 15 CFR 772.1. From the plain language of the export laws and Regulations, it is clear that the EAA and EAR were intended to apply to natural persons and companies extraterritorially, regardless of a person's or company's nationality or locality, so long as items subject to the EAR are involved. In the Matter of Mahdi, 68 FR 57406–02 (Oct. 3, 2003). Thus, it is immaterial whether Micei and/or Montgomery are of a foreign county. To hold otherwise would contravene existing law and regulations, and would completely undermine the effectiveness of the EAA and the EAR. Both Micei and Montgomery are persons subject to the EAR through their actions in exporting activity, giving BIS regulatory authority over them.

B. Default

Generally, the Agency has the burden of proving the allegations in the Charging Letter by reliable, probative, and substantial evidence. 5 U.S.C. 556(d). When the respondent fails to file an answer within the time provided, however, this ''constitutes a waiver of the respondent's right to appear and contest the allegations in the charging letter. In such event, the administrative law judge, on BIS's motion and without further notice to the respondent, shall find the facts to be as alleged in the charging letter and render an initial or recommended decision containing findings of fact and appropriate conclusions of law and issue or recommend an order imposing appropriate sanctions.'' 15 CFR 766.7(a).

In the instant case, BIS filed its original Charging Letter on July 1, 2008. As previously discussed, Respondent did not file an Answer as required under the Regulations, but instead filed a Motion to Dismiss on September 17, 2008. This Motion was denied, but in giving Respondent the benefit of the doubt, this filing was treated as a Motion for Summary Decision and Respondent's time to file an Answer was extended to January 12, 2009. Prior to this deadline on January 9, 2009, BIS filed an Amended Charging Letter adding limited additional allegations serving the same on Respondents via courier and facsimile. This amendment was allowed by rule since Respondent had not yet filed an Answer. 15 CFR 766.3(a). Pursuant to 15 CFR 766,6(a), a Respondent must answer ''within 30 days of notice of any supplement or amendment to a charging letter, unless time is extended under § 766.16 of this part.'' Since there have been no extensions given under § 766.16, Respondent's Answer to the Amended Charging Letter would have been due on February 9, 2009.

Respondent submitted its next filing in this case on February 23, 2009. In addition to the fact that this filing was submitted 14 days after the due date for Respondent to file an Answer, it was not an Answer in form or substance. Instead, it was titled Respondent's Motion for a More Definite Statement and Demand for Hearing. In this filing, Respondent again asserted its previous argument that BIS and the Court lack jurisdiction in this case. Furthermore, this filing was not at all responsive to BIS's Amended Charging Letter and did not admit or deny specifically each separate allegation of the Amended Charging Letter as required under the Regulations. 15 CFR 766.6(b).

On March 5, 2009, Respondent made three additional filings—Response to BIS's Request for Admissions by Respondent Micei International, Response to BIS's First set of Interrogatories and Requests for production of Documents by Respondent Micei International, and Response to BIS's Second set of Interrogators and Requests for Production of Documents by Respondent Micei International. Similar to Respondent's previous filing, these three filings were submitted well after Respondent's time to file an Answer to BIS's Amended Charging Letter and cannot be construed to constitute an Answer in form or substance. Instead, these filings amount to a continuation of Respondent's pattern of declining to follow the regulatory requirement of filing an Answer in this case. This filing was not at all responsive to BIS's Amended Charging Letter and did not admit or deny specifically each separate allegation of the Amended Charging Letter. 15 CFR 766.6(b). Respondent has instead restated the previously rejected argument that no jurisdiction exists in this case and fell short of satisfying its regulatory requirement to file an Answer to BIS's Amended Charging Letter. The Respondent has previously been provided with copies of the procedural regulations and has been given several opportunities to participate in the process provided by the regulations to contest these charges. Respondent has declined to take advantage of this opportunity.

On March 24, 2009, BIS filed a Motion for Default Order arguing that Respondent has yet to file an Answer as required under the Regulations. BIS argued that Respondent's Answer was actually due on February 9, 2009, but due not later then February 19, 2009 under any conceivable construction of the Regulations. I agree.

As of the date of this Order (April 14, 2009) Respondent has still failed to file an Answer (or any other permitted responsive pleading under the Regulations) to BIS's Amended Charging Letter. In light of the fact that Respondent has still not filed an Answer after being given multiple opportunities to properly contest this case within the process provided by the Regulations, BIS's Motion is granted and Respondent is held to be in default. As such, the findings of fact contained in this Order are found as alleged in the Amended Charging Letter. 15 CFR 766.7(a). Appropriate conclusions of law and the recommended sanctions will be based thereon. *Id.*

C. Violations of the EAA and EAR

Micei has been charged with seven (7) counts of counseling, aiding, and abetting Montgomery to violate a BIS Denial Order, and with seven (7) counts of acting with knowledge of a violation.

1. Causing, Aiding or Abetting the Violation of a Denial Order, 15 CFR 764.2(b)

''No person may cause or aid, abet, counsel, command, induce, procure, or permit the doing of any act prohibited, or the omission of any act required, by the EAA, the EAR, or any order, license or authorization issued thereunder.'' 15 CFR 764.2(b). As with most of the 764.2 provisions, 764.2(b) of the Regulations is a strict liability offense. *See* 15 CFR 764.2; *Iran Air* v. *Kugelman,* 996 F.2d 1253, 1258–9 (D.C. Cir. 1993) (upholding the Department of Commerce's reading of the Regulations as allowing for strict liability charges); In the Matter of Kabba & Amir Investments, Inc., d.b.a. Int'l Freight Forwarders, 73 FR 25649, 25652 (May 7, 2008) (concluding that Section 764.2(b) is a strict liability offense), aff'd by Under Secretary, 73 FR 25648; *see also* In the Matter of Petrom GmbH Int'l Trade, 70 FR 32743, 32754 (June 6, 2005). Micei can be found to have counseled, aided, or abetted Montgomery to violate his Denial Order by the Agency demonstrating that Micei participated in the transactions noted in Charges 1–7 and that Montgomery was a ''person denied export privileges'' and subject to a BIS Denial Order. That is, these charges can be found proven against Micei if the actions that Montgomery was taking in connection with Micei would constitute a violation of an active Denial Order. Here, the Respondent is in default and the facts alleged in the charges are deemed proven. I find that the alleged conduct would violate the Denial Order.

On September 22, 2000, Montgomery became a ''person denied export privileges'' when BIS issued a Denial Order against him effective until January 22, 2009. The Denial Order was published in the **Federal Register** on September 22, 2000 (65 FR 57313) and was in continuous effect from September 22, 2000 to January 22, 2009 and continued in force at the time of the actions alleged in the charges.

The Amended Charging Letter alleges that Montgomery's Denial Order mandates that Montgomery ''may not directly or indirectly, participate in any way in any transaction involving any [item] exported or to be exported from the United States, that is subject to the Regulations, or in any other activity subject to the Regulations, including [carrying on negotiations concerning, or ordering, buying, receiving, using, selling, delivering, storing, disposing of, forwarding, transporting, financing, or otherwise servicing in any way, any transaction involving any item exported or to be exported from the United States that is subject to the regulations, or in any other activity subject to the regulations; or * * * [b]enefiting in any way from the transaction involving any item exported or to be exported from the United States that is subject to the Regulations or in any other activity subject to the Regulations.''

As previously discussed, in view of Respondent Micei' s failure to answer the charges, Micei has waived the right to contest the facts as alleged in the Amended Charging Letter in keeping with 15 CFR 766.7(a). The Amended Charging Letter clearly alleges that Montgomery directly and indirectly participated in at least seven (7) transactions involving items to be exported from the United States to Macedonia. This occurred when Montgomery negotiated to be a purchasing agent for Micei for the boots, firing range clearing devices, shoes, remote strobe tubes, shirts, load binders, a ratchet strap, a binder chain, safety shackles, and other items included in order #25473620/017. These goods are subject to the Regulations because they are items of U.S. origin. The Amended Charging Letter goes on to allege that Montgomery participated in and benefited from these transactions.

There is no doubt that the facts alleged in the Amended Charging Letter are sufficient to show that Montgomery was subject to an active Denial Order and that his actions constituted a violation of said Denial Order on each of the seven (7) transactions alleged in the Amended Charging Letter. Clearly then, Micei's authorizing, requesting, and/or arranging Montgomery's actions to purchase boots, firing range clearing devices, shoes, remote strobe tubes, shirts, load binders, a ratchet strap, a binder chain, safety shackles, and other items included in order #25473620/017 constitute causing, aiding, abetting, counseling, commanding, inducing, procuring, or permitting Montgomery to violate said Denial Order. Since knowledge is not a required element for the first seven (7) charges, these facts alone are sufficient to find that Micei's actions constitute seven (7) violations of the EAR as charged.

2. Acting With Knowledge of a Violation 15 CFR 764.2(e)

BIS has also charged Respondent with seven (7) charges alleging that Micei was acting with knowledge of a violation with regard to Montgomery's violation of his Denial Order. As discussed above, Montgomery was subject to an active BIS Denial Order and that his actions and attempted actions were in direct contradiction or violation of the Denial Order. The question then is whether Micei's actions in regard to Montgomery's violation of the Denial Order were taken ''with knowledge'' of a violation. I find that they were and that knowledge of a violation was present.

The Regulations mandate that ''[n]o person may order, buy, remove, conceal, store, use, sell, loan, dispose of, transfer, transport, finance, forward, or otherwise service, in whole or in part, any item exported or to be exported from the United States, or that is otherwise subject to the EAR, with knowledge that a violation of the EAA, the EAR, or any order, license or authorization issued thereunder, has occurred, is about to occur, or is intended to occur in connection with the item.''

In the Amended Charging Letter, BIS alleged that Micei had actual and constructive knowledge that a violation of Montgomery's Denial Order has occurred, is about to occur, or is intended to occur in connection with the items and transactions at issue in this case. Specifically, BIS alleged that shortly after the alleged transactions occurred, Micei, through its vice president, told BIS special investigators that Micei was aware of Montgomery's Denial Order. BIS goes on to allege that Montgomery's Denial Order was published in the **Federal Register** imputing knowledge to Micei that Montgomery was a ''person denied export privileges'' at all relevant times.

It is therefore clear that the allegations are adequate to support the charges that Micei acted ''with knowledge'' that Montgomery was subject to a Denial Order. In keeping with 15 CFR 766.7(a), the facts as alleged are therefore sufficient to prove the seven (7) additional violations in connection with the negotiations and transactions by Montgomery and Micei at issue in this case.

V. Recommended Conclusions of Law

1. The boots, firing range clearing devices, shoes, remote strobe tubes, shirts, load binders, a ratchet strap, a binder chain, safety shackles, and other items included in order #25473620/017 at issue in this case are items subject to the Regulations, giving BIS regulatory authority.

2. Both Montgomery and Micei are ''persons'' subject to the Regulations, giving BIS regulatory authority.

3. Micei has failed to file an Answer to BIS's Amended Charging Letter as required by the Regulations and upon BIS's Motion, Micei is found to be in default.

4. Because Micei has been found to be in default, the facts have been found as alleged in the Amended Charging Letter.

5. At all relevant times, Montgomery was subject to a BIS Denial Order and violated said Denial Order seven (7) times between on or about July 2, 2003 and on or about October 8, 2003.

6. On seven (7) occasions between on or about July 2, 2003 and on or about October 8, 2003 Micei caused, aided, or abetted Montgomery to violate a standing BIS Denial Order.

7. On seven (7) occasions between on or about July 2, 2003 and on or about October 8, 2003 Micei acted with knowledge of a violation when it caused, aided, or abetted Montgomery to violate a standing BIS Denial Order.

VI. Recommended Sanction

BIS has proposed a sanction against Micei of a five- (5)-year denial of U.S. export privileges under 15 CFR 764.3(a)(2) and a $126,000.00 civil penalty under 15 CFR 764.3(a)(1). BIS argues that this penalty is appropriate because Micei has deliberately participated in multiple export transactions of items from the United States to Macedonia involving violations of a BIS Denial Order with knowledge of the violations. BIS goes on to assert that Micei has demonstrated a ''severe and blatant disregard for U.S. export control laws'' and that this is highlighted by Respondent's conduct during the various phases of this Enforcement Action.

BIS cites several previous export enforcement cases wherein similar conduct and violations were assessed a penalty comparable to that which has been proposed in this case. In the Matter of Suburban Guns (Pty) Ltd., Docket No. 05–BIS–02, 70 FR 69,314 (Nov. 15, 2005). In Suburban Guns, the ALJ found that Respondent ordered firearm parts and accessories from a U.S. supplier and had them exported from the U.S. to its location in South Africa on two occasions in violation of a standing Denial Order. The ALJ recommended a five- (5)-year denial of export privileges and a civil penalty of $44,000. However, each case is determined separately based on the individual facts and circumstances presented.

While Micei's conduct in the instant case is, to some extent, analogous to that of the respondents in the above mentioned cases, the information in the record could support an assertion that the violations are intentional and that could justify a significantly harsher penalty than that which BIS proposes. Micei has failed to contest for the charged violation of U.S. export laws and regulations in declining to follow the Regulations provided and failing to meet the deadlines provided in the Regulations and by the Orders issued in this matter. However, since the record in this matter is limited because it is being decided on a default motion, and Micei has also waived an opportunity to present any mitigating evidence it may have, I do not recommend increasing the penalty proposed by BIS. Therefore, I recommend that BIS's proposed penalty of a five- (5)-year denial of export privileges and a $126,000 civil penalty are deemed appropriate.

VII. Recommended Order

[REDACTED SECTION]

[REDACTED SECTION]

The Recommended Decision and Order is being referred to the Under Secretary for review and final action. As provided by Section 766.17(b)(2) of the EAR, the recommended decision and order is being served by express mail. Because the Under Secretary must review the decision in a short time frame, all papers filed with the Under Secretary in response to the recommended decision and order must be sent by personal delivery, facsimile, express mail, or other overnight carrier as provided in Section 766.22(a) of the EAR. Submissions by the parties must be filed with the Under Secretary for Export Administration, Bureau of Industry and Security, U.S. Department of Commerce, Room H–3898, 14th Street and Constitution Avenue, NW., Washington, DC 20230, within 12 days from the date of issuance of this Recommended Decision and Order. Thereafter, the parties have eight days from receipt of any response(s) in which to submit replies.

Within 30 days after receipt of this Recommended Decision and Order, the Under Secretary shall issue a written order, affirming, modifying or vacating the recommended decision and order. *See* 15 CFR 766.22(c).

PLEASE TAKE NOTE THAT Respondent has one year from the date of entry of this Order to file a petition to vacate this default order. 15 CFR 766.7(b).

Administrative Law Judge in Norfolk, Virginia.

Done and dated April 14, 2009.
Norfolk, VA.

Hon. Michael J. Devine,
Administrative Law Judge, U.S. Coast Guard.

6. United States Coast Guard Administrative Law Judges perform adjudicatory functions for the Bureau of Industry and Security with approval from the Office of Personnel Management pursuant to a memorandum of understanding between the Coast Guard and the Bureau of Industry and Security.

Certificate of Service

I hereby certify that I have served the foregoing Scheduling Order upon the following parties (or designated representatives) at the address indicated below:

Eric Clark, Attorney-Advisor and Parvin Huda, Senior Counsel, and Joseph Jest, Chief of Enforcement and Litigation, Attorneys for Bureau of Industry and Security, Office of Chief Counsel for Industry and Security. U.S. Department of Commerce, Room H–3839, 14th Street & Constitution Avenue, NW., Washington, DC 20230. *Fax:* 202–482–0085. Sent by Facsimile and Federal Express.

Vasko Tomanovic, Counsel for Respondent, ''Kaminik'' b.b., 1000 Skopje, Republic of Macedonia. *Tel:* 389–70–436068. *Fax:* 41–44–567–1892. Sent by Facsimile and Federal Express.

ALJ Docketing Center, Attn: Hearing Docket Clerk, United States Coast Guard, 40 South Gay Street, Rm. 412, Baltimore, MD 21202. *Fax:* 410–962–1746. Sent by Facsimile and Federal Express.

Mr. Iki Malinkovski, Micei International, Kaminik b.b., 1000 Skopje, Republic of Macedonia. *Fax:* 011–389–2252–2039. Sent by Facsimile and Federal Express.

Done and dated April 14, 2009.

Janice L. Parker,
Paralegal Assistant to the Administrative Law Judge.

Notice to the Parties Regarding Review by Under Secretary.

Title 15—Commerce and Foreign Trade.
Subtitle B—Regulations Relating to Commerce and Foreign Trade.
Chapter VII—Bureau of Industry and Security, Department of Commerce.
Subchapter C—Export Administration Regulations.
Part 766—Administrative Enforcement Proceedings.
15 CFR 766.22.

§ 766.22 Review by Under Secretary

(a) *Recommended decision.* For proceedings not involving violations relating to part 760 of the EAR, the administrative law judge shall immediately refer the recommended decision and order to the Under Secretary. Because of the time limits provided under the EAA for review by the Under Secretary, service of the recommended decision and order on the parties, all papers filed by the parties in response, and the final decision of the Under Secretary must be by personal delivery, facsimile, express mail or other overnight carrier. If the Under Secretary cannot act on a recommended decision and order for any reason, the Under Secretary will designate another Department of Commerce official to receive and act on the recommendation.

(b) *Submissions by parties.* Parties shall have 12 days from the date of issuance of the recommended decision and order in which to submit simultaneous responses. Parties thereafter shall have eight days from receipt of any response(s) in which to submit replies. Any response or reply must be received within the time specified by the Under Secretary.

(c) *Final decision.* Within 30 days after receipt of the recommended decision and order, the Under Secretary shall issue a written order affirming, modifying or vacating the recommended decision and order of the administrative law judge. If he/she vacates the recommended decision and order, the Under Secretary may refer the case back to the administrative law judge for further proceedings. Because of the time limits, the Under Secretary's review will ordinarily be limited to the written record for decision, including the transcript of any hearing, and any submissions by the parties concerning the recommended decision.

(d) *Delivery.* The final decision and implementing order shall be served on the parties and will be publicly available in accordance with § 766.20 of this part.

(e) *Appeals.* The charged party may appeal the Under Secretary's written order within 15 days to the United States Court of Appeals for the District of Columbia pursuant to 50 U.S.C. app. 2412(c)(3).

[FR Doc. E9–11885 Filed 5–22–09; 8:45 am]
BILLING CODE M

DEPARTMENT OF COMMERCE

International Trade Administration

A–552–802

Certain Frozen Warmwater Shrimp from the Socialist Republic of Vietnam: Final Results of the Second New Shipper Review

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

SUMMARY: The Department of Commerce (''Department'') is conducting a new shipper review of BIM Seafood Joint Stock Company (''BIM Seafood'') and the antidumping duty order on certain frozen warmwater shrimp from the Socialist Republic of Vietnam (''Vietnam''). *See Notice of Amended Final Determination of Sales at Less Than Fair Value and Antidumping Duty Order: Certain Frozen Warmwater Shrimp From the Socialist Republic of Vietnam*, 70 FR 5152 (February 1, 2005) (''*Shrimp Order.*'') We preliminarily found that BIM Seafood did not sell subject merchandise at less than normal value (''NV'') and thus assigned a zero margin for the period of review (''POR''), February 1, 2007, through January 31, 2008. *See Certain Frozen*

Warmwater Shrimp from the Socialist Republic of Vietnam: Preliminary Results of the Second New Shipper Review, 74 FR 4924 (January 28, 2009) (''*Preliminary Results*''). Based upon our analysis of the comments and information received, we made changes to the margin calculations for the final results. The final margin is listed below in the section entitled, ''Final Results of the Review.''

EFFECTIVE DATE: May 26, 2009.

FOR FURTHER INFORMATION CONTACT: Emeka Chukwudebe, AD/CVD Operations, Office 9, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue, NW, Washington DC 20230; telephone: (202) 482–0219.

SUPPLEMENTARY INFORMATION:

Case History

On January 28, 2009, the Department published in the **Federal Register** the preliminary results of this second new shipper review. On February 27, 2009, BIM Seafood filed comments regarding the Department's *Preliminary Results*. On March 20, 2009, the Department issued a revised margin analysis memorandum to the file. *See* Memorandum to the File, from Emeka Chukwudebe, Case Analyst, Office 9, Import Administration, through Alex Villanueva, Program Manager, Office 9, regarding ''New Shipper Review of Certain Frozen Warmwater Shrimp from the Socialist Republic of Vietnam'' dated March 20, 2009 (''Revised Margin Analysis Memo''). We gave BIM Seafood an opportunity to comment on the Revised Margin Analysis Memo. On March 30, 2009, BIM Seafood filed comments regarding the Department's Revised Margin Analysis Memo. No other party filed comments and no party requested a public hearing. On April 15, 2009, the Department extended the time limit for the completion of the final results of this new shipper review by 60 days. *See Certain Frozen Warmwater Shrimp From the Socialist Republic of Vietnam: Extension of Time Limit for Final Results of the Second New Shipper Review*, 74 FR 17453 (April 15, 2009).

Scope of the Order

The scope of the order includes certain frozen warmwater shrimp and prawns, whether wild–caught (ocean harvested) or farm–raised (produced by aquaculture), head–on or head–off, shell–on or peeled, tail–on or tail–off,[1] deveined or not deveined, cooked or raw, or otherwise processed in frozen form.

The frozen warmwater shrimp and prawn products included in the scope of the order, regardless of definitions in the Harmonized Tariff Schedule of the United States (''HTSUS''), are products which are processed from warmwater shrimp and prawns through freezing and which are sold in any count size.

The products described above may be processed from any species of warmwater shrimp and prawns. Warmwater shrimp and prawns are generally classified in, but are not limited to, the Penaeidae family. Some examples of the farmed and wild–caught warmwater species include, but are not limited to, whiteleg shrimp (*Penaeus vannemei*), banana prawn (*Penaeus merguiensis*), fleshy prawn (*Penaeus chinensis*), giant river prawn (*Macrobrachium rosenbergii*), giant tiger prawn (*Penaeus monodon*), redspotted shrimp (*Penaeus brasiliensis*), southern brown shrimp (*Penaeus subtilis*), southern pink shrimp (*Penaeus notialis*), southern rough shrimp (*Trachypenaeus curvirostris*), southern white shrimp (*Penaeus schmitti*), blue shrimp (*Penaeus stylirostris*), western white shrimp (*Penaeus occidentalis*), and Indian white prawn (*Penaeus indicus*).

Frozen shrimp and prawns that are packed with marinade, spices or sauce are included in the scope of the order. In addition, food preparations, which are not ''prepared meals,'' that contain more than 20 percent by weight of shrimp or prawn are also included in the scope of the order.

Excluded from the scope are: 1) breaded shrimp and prawns (HTSUS subheading 1605.20.10.20); 2) shrimp and prawns generally classified in the Pandalidae family and commonly referred to as coldwater shrimp, in any state of processing; 3) fresh shrimp and prawns whether shell–on or peeled (HTSUS subheadings 0306.23.00.20 and 0306.23.00.40); 4) shrimp and prawns in prepared meals (HTSUS subheading 1605.20.05.10); 5) dried shrimp and prawns; 6) canned warmwater shrimp and prawns (HTSUS subheading 1605.20.10.40); 7) certain dusted shrimp; and 8) certain battered shrimp. Dusted shrimp is a shrimp–based product: 1) that is produced from fresh (or thawed–from-frozen) and peeled shrimp; 2) to which a ''dusting'' layer of rice or wheat flour of at least 95 percent purity has been applied; 3) with the entire surface of the shrimp flesh thoroughly and evenly coated with the flour; 4) with the non–shrimp content of the end product constituting between four and 10 percent of the product's total weight after being dusted, but prior to being frozen; and 5) that is subjected to individually quick frozen (''IQF'') freezing immediately after application of the dusting layer. Battered shrimp is a shrimp–based product that, when dusted in accordance with the definition of dusting above, is coated with a wet viscous layer containing egg and/or milk, and par–fried.

The products covered by the order are currently classified under the following HTSUS subheadings: 0306.13.00.03, 0306.13.00.06, 0306.13.00.09, 0306.13.00.12, 0306.13.00.15, 0306.13.00.18, 0306.13.00.21, 0306.13.00.24, 0306.13.00.27, 0306.13.00.40, 1605.20.10.10, and 1605.20.10.30. These HTSUS subheadings are provided for convenience and for customs purposes only and are not dispositive, but rather the written description of the scope of the order is dispositive.

Analysis of Comments Received

All issues raised in the comments by BIM Seafood are addressed in the concurrent Issues and Decision Memorandum (''Issues and Decision Memo''), which is hereby adopted by this notice. A list of the issues which BIM Seafood raised and to which we respond in the Issues and Decision Memo is attached to this notice as an Appendix. The Issues and Decision Memo is a public document and is on file in the Central Records Unit (''CRU''), Main Commerce Building, Room 1117, and is accessible on the Web at http://www.trade.gov/ia. The paper copy and electronic version of the memorandum are identical in content.

Changes Since the Preliminary Results

Based on our analysis of information and comments received regarding our *Preliminary Results* and Revised Margin Analysis Memo, we have made revisions to the margin calculations for BIM Seafood. For all changes to the calculations, see the Issues and Decision Memo at Comment 1 and 2.

Final Results of the Review

The Department has determined that the final dumping margin for the POR is:

CERTAIN FROZEN WARMWATER SHRIMP FROM VIETNAM

Manufacturer/Exporter	Weighted–Average Margin (Percent)
BIM Seafood	0.00

[1] ''Tails'' in this context means the tail fan, which includes the telson and the uropods.

Assessment Rates

Upon issuance of the final results, the Department will determine, and U.S. Customs and Border Protection (''CBP'') shall assess, antidumping duties on all appropriate entries. The Department intends to issue assessment instructions to CBP 15 days after the date of publication of the final results of review. Pursuant to 19 CFR 351.212(b)(1), we will calculate importer–specific (or customer) *ad valorem* duty assessment rates based on the ratio of the total amount of the dumping margins calculated for the examined sales to the total entered value of those same sales. We will instruct CBP to assess antidumping duties on all appropriate entries covered by this review if any importer–specific assessment rate calculated in the final results of this review is above de minimis.

Cash–Deposit Requirements

The following cash deposit requirements will be effective upon publication of these final results of the new shipper review for all shipments of subject merchandise by BIM Seafood, entered, or withdrawn from warehouse, for consumption on or after the publication date, as provided by section 751(a)(2)(C) of the Tariff Act of 1930, as amended (''Act''): (1) for subject merchandise produced and exported by BIM Seafood, the cash deposit rate will be zero; (2) for subject merchandise exported by BIM Seafood, but not manufactured by BIM Seafood, the cash deposit rate will continue to be the Vietnam–wide rate of 25.76 percent; and (3) for subject merchandise manufactured by BIM Seafood, but exported by any party other than BIM Seafood, the cash deposit rate will be the rate applicable to the exporter. These cash deposit requirements will remain in effect until further notice.

Reimbursement of Duties

This notice also serves as a final reminder to importers of their responsibility under 19 CFR 351.402(f) to file a certificate regarding the reimbursement of antidumping duties prior to liquidation of the relevant entries during this POR. Failure to comply with this requirement could result in the Department's presumption that reimbursement of antidumping duties has occurred and the subsequent assessment of doubled antidumping duties.

Administrative Protective Orders

This notice also serves as a 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, which continues to govern business proprietary information in this segment of the proceeding. Timely written notification of the return/destruction of APO materials or conversion to judicial protective order is hereby requested. Failure to comply with the regulations and terms of an APO is a violation which is subject to sanction.

We are issuing and publishing this determination in accordance with sections 751(a)(2)(B) and 777(i) of the Act, and 19 CFR 351.214(h) and 351.221(b)(5).

Dated: May 18, 2009.

Ronald K. Lorentzen,

Acting Assistant Secretary for Import Administration.

Appendix - Issues and Decision Memorandum

Comment 1: International Freight
Comment 2: Raw Shrimp Count–Size Conversion

[FR Doc. E9–12152 Filed 5–22–09; 8:45 am]

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DEPARTMENT OF COMMERCE

Foreign-Trade Zones Board

[Order No. 1620]

Grant of Authority for Subzone Status; Grafil, Inc. (Carbon Fiber), Sacramento, CA

Pursuant to its authority under the Foreign-Trade Zones Act of June 18, 1934, as amended (19 U.S.C. 81a–81u), the Foreign-Trade Zones Board (the Board) adopts the following Order:

Whereas, the Foreign-Trade Zones Act provides for ''* * * the establishment * * * of foreign-trade zones in ports of entry of the United States, to expedite and encourage foreign commerce, and for other purposes,'' and authorizes the Foreign-Trade Zones Board to grant to qualified corporations the privilege of establishing foreign-trade zones in or adjacent to U.S. Customs and Border Protection ports of entry;

Whereas, the Board's regulations (15 CFR part 400) provide for the establishment of special-purpose subzones when existing zone facilities cannot serve the specific use involved, and when the activity results in a significant public benefit and is in the public interest;

Whereas, the Sacramento-Yolo Port District, grantee of FTZ 143, has made application to the Board for authority to establish special-purpose subzone status at the carbon fiber manufacturing plant of Grafil, Inc., located in Sacramento, California (FTZ Docket 37–2007, filed 8/14/2007);

Whereas, notice inviting public comment has been given in the **Federal Register** (72 FR 48612, 8/24/07); and,

Whereas, the Board adopts the findings and recommendations of the examiner's report, and finds that the requirements of the FTZ Act and the Board's regulations would be satisfied, and that approval of the application would be in the public interest, if approval were subject to the condition listed below;

Now, therefore, the Board hereby grants authority for subzone status for activity related to the manufacture of carbon fiber at the Grafil, Inc., facilities, located in Sacramento, California (Subzone 143D), as described in the application and **Federal Register** notice, subject to the FTZ Act and the Board's regulations, including Section 400.28, and also subject to the condition that approval is for an initial period of five years, subject to extension upon review.

Signed at Washington, DC, this 7th day of May 2009.

Ronald K. Lorentzen,

Acting Assistant Secretary of Commerce for Import Administration, Alternate Chairman, Foreign-Trade Zones Board.

Andrew McGilvray,

Executive Secretary.

[FR Doc. E9–12129 Filed 5–22–09; 8:45 am]

BILLING CODE P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

Hydrographic Services Review Panel; Membership Solicitation

AGENCY: National Ocean Service, National Oceanic and Atmospheric Administration (NOAA), Department of Commerce.

ACTION: Notice of membership solicitation for Hydrographic Services Review Panel.

SUMMARY: This notice responds to the Hydrographic Services Improvement Act Amendments of 2002, Public Law 107–372, which requires the Under Secretary of Commerce for Oceans and Atmosphere to solicit nominations for membership on the Hydrographic Services Review Panel (the Panel). This advisory committee will advise the Under Secretary on matters related to the responsibilities and authorities set forth in section 303 of the Hydrographic Services Improvement Act of 1998, and

such other appropriate matters as the Under Secretary refers to the Panel for review and advice.

DATES: Résumés should be sent to the address, e-mail, or fax specified and must be received by June 26, 2009.

ADDRESSES: Director, Office of Coast Survey, National Ocean Service, NOAA (N/CS), 1315 East West Highway, Silver Spring, MD 20910, fax: 301–713–4019, e-mail: *Hydroservices.panel@noaa.gov*.

FOR FURTHER INFORMATION CONTACT: Captain Steven Barnum, NOAA, Director, Office of Coast Survey, National Ocean Service (NOS), NOAA (N/CS), 1315 East West Highway, Silver Spring, Maryland 20910; Telephone: 301–713–2770, Fax: 301–713–4019; e-mail: *steven.barnum@noaa.gov*.

SUPPLEMENTARY INFORMATION: Under 33 U.S.C. 883a, *et seq*., NOAA's National Ocean Service (NOS) is responsible for providing nautical charts and related information for safe navigation. NOS collects and compiles hydrographic, tidal and current, geodetic, and a variety of other data in order to fulfill this responsibility. The Hydrographic Services Review Panel provides advice on topics such as ''NOAA's Hydrographic Survey Priorities,'' technologies relating to operations, research and development of data pertaining to:

(a) Hydrographic surveying;
(b) Nautical charting;
(c) Water level measurements;
(d) Current measurements;
(e) Geodetic measurements; and
(f) Geospatial measurements.

The Panel comprises fifteen voting members appointed by the Under Secretary in accordance with section 105 of Public Law 107–372. Members are selected on a standardized basis, in accordance with applicable Department of Commerce guidance. The Co-Director of the Joint Hydrographic Center and two other employees of the National Oceanic and Atmospheric Administration serve as nonvoting members of the Panel. The Director, Office of Coast Survey, serves as the Designated Federal Official (DFO). This solicitation is to obtain candidate applications for one current voting vacancy on the Panel, and for five voting members whose terms expire January 1, 2010, and candidates for voting members who might resign at any time during 2009. Be advised that some voting members whose terms expire January 1, 2010, may be reappointed for another full term if eligible.

Voting members are individuals who, by reason of knowledge, experience, or training, are especially qualified in one or more disciplines relating to hydrographic surveying, tides, currents, geodetic and geospatial measurements, marine transportation, port administration, vessel pilotage, and coastal or fishery management. An individual may not be appointed as a voting member of the Panel if the individual is a full-time officer or employee of the United States. Any voting member of the Panel who is an applicant for, or beneficiary of (as determined by the Under Secretary) any assistance under the Act shall disclose to the Panel that relationship, and may not vote on any other matter pertaining to that assistance.

Voting members of the Panel serve a four-year term, except that vacancy appointments shall be for the remainder of the unexpired term of the vacancy. Members serve at the discretion of the Under Secretary and are subject to government ethics standards. Any individual appointed to a partial or full term may be reappointed for one additional full term. A voting member may serve until his or her successor has taken office. The Panel selects one voting member to serve as the Chair and another to serve as the Vice Chair. The Vice Chair acts as Chair in the absence or incapacity of the Chair but will not automatically become the Chair if the Chair resigns. Meetings occur at least twice a year, and at the call of the Chair or upon the request of a majority of the voting members or of the Under Secretary. Voting members receive compensation at a rate established by the Under Secretary, not to exceed the maximum daily rate payable under section 5376 of title 5, United States Code, when engaged in performing duties for the Panel. Members are reimbursed for actual and reasonable expenses incurred in performing such duties.

Panel members selected to serve on the HSRP FACA committee must complete the following:

(a) Security Clearance (on-line Background Security Check process and fingerprinting conducted through NOAA Workforce Management);

(b) Confidential Financial Disclosure Report—As an SGE you are required to file a Confidential Financial Disclosure Report to avoid involvement in a real or apparent conflict of interest. You may find the Confidential Financial Disclosure Report at the following Web site: *http://www.usoge.gov/forms/form_450.aspx*.

(c) Certification of Status Statement (certifying statement that as an SGE you are not an agent of a foreign principal or a lobbyist—document provided by NOAA).

Dated: May 19, 2009.

Captain Steven Barnum,

NOAA, Director, Office of Coast Survey, National Ocean Service, National Oceanic and Atmospheric Administration.

[FR Doc. E9–12066 Filed 5–22–09; 8:45 am]

BILLING CODE P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XO71

Incidental Takes of Marine Mammals During Specified Activities; Low-Energy Marine Seismic Survey in the Northeast Pacific Ocean, July 2009

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

ACTION: Notice; proposed incidental take authorization; request for comments.

SUMMARY: NMFS has received an application from the Scripps Institution of Oceanography (SIO), a part of the University of California San Diego (UCSD), for an Incidental Harassment Authorization (IHA) to take small numbers of marine mammals, by harassment, incidental to conducting a marine seismic survey in the Northeast Pacific Ocean during July 2009. Pursuant to the Marine Mammal Protection Act (MMPA), NMFS requests comments on its proposal to authorize SIO to incidentally take, by Level B harassment only, small numbers of marine mammals during the aforementioned activity.

DATES: Comments and information must be received no later than June 25, 2009.

ADDRESSES: Comments on the application should be addressed to Michael Payne, Chief, Permits, Conservation and Education Division, Office of Protected Resources, National Marine Fisheries Service, 1315 East-West Highway, Silver Spring, MD 20910–3225. The mailbox address for providing email comments is *PR1.0648–XO71@noaa.gov*. Comments sent via e-mail, including all attachments, must not exceed a 10–megabyte file size.

A copy of the application containing a list of the references used in this document may be obtained by writing to the address specified above, telephoning the contact listed below (see **FOR FURTHER INFORMATION CONTACT**), or visiting the internet at: *http://www.nmfs.noaa.gov/pr/permits/incidental.htm*.

Documents cited in this notice may be viewed, by appointment, during regular business hours, at the aforementioned address.

FOR FURTHER INFORMATION CONTACT: Howard Goldstein or Ken Hollingshead, Office of Protected Resources, NMFS, 301–713–2289.

SUPPLEMENTARY INFORMATION:

Background

Sections 101(a)(5)(A) and (D) of the MMPA (16 U.S.C. 1361 *et seq.*) direct the Secretary of Commerce to allow, upon request, the incidental, but not intentional, taking of marine mammals by United States citizens who engage in a specified activity (other than commercial fishing) within a specified geographical region if certain findings are made and either regulations are issued or, if the taking is limited to harassment, a notice of a proposed authorization is provided to the public for review.

Authorization for incidental taking shall be granted if NMFS finds that the taking will have a negligible impact on the species or stock(s), will not have an unmitigable adverse impact on the availability of the species or stock(s) for subsistence uses, and if the permissible methods of taking and requirements pertaining to the mitigation, monitoring and reporting of such takings are set forth. NMFS has defined ''negligible impact'' in 50 CFR 216.103 as ''...an impact resulting from the specified activity that cannot be reasonably expected to, and is not reasonably likely to, adversely affect the species or stock through effects on annual rates of recruitment or survival.''

Section 101(a)(5)(D) of the MMPA established an expedited process by which citizens of the United States can apply for an authorization to incidentally take small numbers of marine mammals by harassment. Except with respect to certain activities not pertinent here, the MMPA defines ''harassment'' as:

> any act of pursuit, torment, or annoyance which (i) has the potential to injure a marine mammal or marine mammal stock in the wild [ALevel A harassment@]; or (ii) has the potential to disturb a marine mammal or marine mammal stock in the wild by causing disruption of behavioral patterns, including, but not limited to, migration, breathing, nursing, breeding, feeding, or sheltering [ALevel B harassment@].

Section 101(a)(5)(D) establishes a 45–day time limit for NMFS= review of an application followed by a 30–day public notice and comment period on any proposed authorizations for the incidental harassment of small numbers of marine mammals. Within 45 days of the close of the comment period, NMFS must either issue or deny issuance of the authorization.

Summary of Request

On March 9, 2009, NMFS received an application from SIO for the taking, by Level B harassment only, of small numbers of marine mammals incidental to conducting, under cooperative agreement with the National Science Foundation (NSF), a low-energy marine seismic survey in the Northeast Pacific Ocean. The funding for the survey is provided by the NSF. The proposed survey will occur in an overall area between approximately 44° and 45° N. and 124.5° and 126° W. within the Exclusive Economic Zone (EEZ) of the U.S.A., and is scheduled to occur from July 14–20, 2009. The survey will use a single Generator Injector (GI) airgun with a discharge volume of 45 in^3. Some minor deviation from these dates is possible, depending on logistics and weather.

The proposed survey is virtually identical to one conducted by SIO in 2007 under an IHA issued in September 2007 (NMFS 2007). The proposed SIO 2009 IHA application contains minor updates to the project description, updated marine mammal population sizes based on the most recent NMFS annual stock assessment, an assessment of the relevance of the marine mammal density and distribution data contained in the SIO 2007 IHA application based on cruise reports from the NMFS SWFSC ORCAWHALE 2008 cruise, and updated information on effects of airguns on marine mammals (see Appendix A of SIO's application).

Description of the Specified Activity

SIO plans to conduct an ocean bottom seismograph (OBS) deployment and a magnetic, bathymetric, and seismic survey. The planned survey will involve one source vessel, the R/V *Wecoma* (*Wecoma*), and will occur in the Northeast Pacific Ocean off the coast of Oregon.

The purpose of the research program is to record micro-earthquakes in the forearc to determine whether seismicity on the plate boundary is characteristic of a locked or a freely slipping fault plane. Several earthquakes large enough to be recorded on land-based seismic nets have occurred along this segment in the past several years. The occurrence of ''repeating earthquakes'' (earthquakes with identical waveforms indicating repeated rupture of almost the same fault patch) suggests that this region is at a boundary between a freely slipping and a locked portion of the fault. Some models suggest that the forearc basin north of the seismically active zone may be locked; others suggest that portion of the fault is slipping freely. OBSs have been deployed for a year, and a seismic survey will be used to characterize the shallow sediment structure around the instruments. Also, included in the research is the use of a magnetometer and sub-bottom profiler.

The source vessel, the *Wecoma*, will deploy a single low-energy GI airgun as an energy source (with a discharge volume of 45 in^3) and a 300 m (984 ft), 16 channel, towed hydrophone streamer. Sixteen OBSs were deployed in July and September 2008. They will continue to acquire data during this cruise, and will be recovered before returning to port. The energy to the GI airgun is compressed air supplied by compressors onboard the source vessel. As the GI airgun is towed along the survey lines, the receiving systems will receive the returning acoustic signals.

The seismic program will consist of approximately 21 km (13 mi) of surveys over each of the 16 OBSs (see Figure 1 of SIO's application). Water depths at the seismic survey locations rang from just less than 100 m (328 ft) to almost 3,000 m (9,842 ft) (see Figure 1 of SIO's application). The GI airgun will be operated on a small grid for approximately two hours at each of the 16 OBS sites. There will be additional seismic operations associated with equipment testing, start-ups, and repeat coverage of any areas where initial data quality is substandard.

All planned geophysical data acquisition activities will be conducted by SIO with on-board assistance by the scientists who have proposed the study. The Chief Scientist is Dr. Anne Trehu of Oregon State University. The vessel will be self-contained, and the crew will live aboard the vessel for the entire cruise.

In addition to the seismic operations of the single GI airgun, a 3.5 and 12 kHz sub-bottom profiler will be used continuously throughout the cruise, and a magnetometer may be run on the transit between OBS locations.

Vessel Specifications

The *Wecoma* has a length of 56.4 m (185 ft), a beam of 10.1 m (33.1 ft), and a maximum draft of 5.6 m (18.4 ft). The ship is powered by a single 3,000–hp EMD diesel engine driving a single, controllable-pitch propeller through a clutch and reduction gear, and an electric 350–hp azimuthing bow thruster. An operations speed of 11.1 km/hour (6 knots) will be used during seismic acquisition. When not towing seismic survey gear, the *Wecoma* cruises at 22.2 km/hour (12 knots) and has a maximum speed of 26 km/hour (14 knots). It has a normal operating range of approximately 13,300 km. The *Wecoma* will also serve as the platform from which vessel-based Marine Mammal Visual Observers (MMVO) will watch for animals before and during GI airgun operations.

Acoustic Source Specifications

Seismic Airguns

During the proposed survey, the *Wecoma* will tow a single GI airgun, with a volume of 45 in^3, and a 300 m long streamer containing hydrophones along predetermined lines. Seismic pulses will be emitted at intervals of 10 seconds. At a speed of 6 knots (11.1 km/hour), the 10 second shot spacing corresponds to a shot interval of approximately 31 m (101.7 ft).

The generator chamber of the GI airgun, the one responsible for introducing the sound pulse into the ocean, is 45 in^3. The larger (105 in^3) injector chamber injects air into the previously-generated bubble to maintain its shape, and does not introduce more sound into the water. The 45 in^3 GI airgun will be towed 21 m (68.9 ft) behind the *Wecoma* at a depth of 4 m (13.1ft). The sound pressure field of that GI airgun variation at a tow depth of 2.5 m has been modeled by Lamont-Doherty Earth Observatory (L-DEO) in relation to distance and direction for the GI airgun.

As the GI airgun is towed along the survey line, the towed hydrophone array in the 300 m streamer receives the reflected signals and transfers the data on the on-board processing system. Given the relatively short streamer length behind the vessel, the turning rate of the vessel while the gear is deployed is much higher than the limit of five degrees per minute for a seismic vessel towing a streamer of more typical length (much greater than 1 km). Thus, the maneuverability of the vessel is not limited much during operations.

The root mean square (rms) received levels that are used as impact criteria for marine mammals are not directly comparable to the peak (pk or 0–pk) or peak-to-peak (pk - pk) values normally used to characterize source levels of airgun arrays. The measurement units used to describe airgun sources, peak or peak-to-peak decibels, are always higher than the ''root mean square'' (rms) decibels referred to in biological literature. A measured received level of 160 dB re 1 μPa (rms) in the far field would typically correspond to a peak measurement of approximately 170 to 172 dB, and to a peak-to-peak measurement of approximately 176 to 178 dB, as measured for the same pulse received at the same location (Greene, 1997; McCauley *et al.*, 1998, 2000). The precise difference between rms and peak or peak-to-peak values depends on the frequency content and duration of the pulse, among other factors. However, the rms level is always lower than the peak or peak-to-peak level for an airgun-type source.

Received sound levels have been modeled by L-DEO for a number of airgun configurations, including one 45 in^3 GI airgun, in relation to distance from the airgun(s) (see Figure 2 of SIO's application). The model does not allow for bottom interactions, and is most directly applicable to deep water. Based on modeling, estimates of the maximum distances from the GI airgun where sound levels of 190, 180, and 160 dB re 1 μPa (rms) are predicted to be received in deep (≤1,000 m) water are shown in Table 1 of SIO's application. Because the model results are for a 2.5 m tow depth, the distances in Table 1 slightly underestimate the distances for the 45 in^3 GI airgun towed at 4 m depth.

Sub-bottom Profiler

Along with the GI airgun operations, one additional acoustical data acquisition system will be operated throughout the cruise. The ocean floor will be mapped with a Knudsen Engineering Model 320BR 12 kHz and 3.5 kHz sub-bottom profiler (SBP). Multi-beam sonar will not be used.

The Knudsen Engineering Model 320BR SBP is a dual-frequency transceiver designed to operate at 3.5 and/or 12 kHz. It is used to provide data about the sedimentary features that occur below the sea floor. The energy from the sub-bottom profiler is directed downward via a 12 kHz transducer (EDO 323B) or a 3.5 kHz array of 16 ORE 137D transducers in a 4x4 arrangement. The maximum power output of the 320BR is 10 kilowatts for the 3.5 kHz section and 2 kilowatts for the 12 kHz section.

The pulse length for the 3.5 kHz section of the 320 BR is 0.8–24 ms, controlled by the system operator in regards to water depth and reflectivity of the bottom sediments, and will usually be 12 or 24 ms in this survey. The system produces one sound pulse and then waits for its return before transmitting again. Thus, the pulse interval is directly dependent upon water depth, and in this survey is 4.5–8 seconds. Using the Sonar Equations and assuming 100 percent efficiency in the system (impractical in real world applications), the source level for the 320BR is calculated to be 211 dB re 1 Pam. In practical operation, the 3.5 kHz array is seldom driven at more than 80 percent of maximum, usually less than 50 percent.

Safety Radii

NMFS has determined that for acoustic effects, using acoustic thresholds in combination with corresponding safety radii is an effective way to consistently apply measures to avoid or minimize the impacts of an action, and to quantitatively estimate the effects of an action. Thresholds are used in two ways: (1) to establish a mitigation shut-down or power-down zone, i.e., if an animal enters an area calculated to be ensonified above the level of an established threshold, a sound source is powered down or shut down; and (2) to calculate take, in that a model may be used to calculate the area around the sound source that will be ensonified to that level or above, then, based on the estimated density of animals and the distance that the sound source moves, NMFS can estimate the number of marine mammals that may be ''taken.''

As a matter of past practice and based on the best available information at the time regarding the effects of marine sound compiled over the past decade, NMFS has used conservative numerical estimates to approximate where Level A harassment from acoustic sources begins: 180 dB re 1 μPa (rms) level for cetaceans and 190 dB re 1 μPa (rms) for pinnipeds. A review of the available scientific data using an application of science-based extrapolation procedures (Southall *et al.*, 2007) strongly suggests that Level A harassment (as well as TTS) from single sound exposure impulse events may occur at much higher levels than the levels previously estimated using very limited data. However, for purposes of this proposed action, SIO's application sets forth, and NMFS is using, the more conservative 180 and 190 dB re 1 μPa (rms) criteria. NMFS also considers 160 dB re 1 μPa (rms) as the criterion for estimating the onset of Level B harassment from acoustic sources like impulse sounds used in the seismic survey.

Emperical data concerning the 180 and 160 dB distances have been acquired based on measurements during the acoustic verification study conducted by L-DEO in the northern Gulf of Mexico from May 27 to June 3, 2003 (Tolstoy *et al.*, 2004). Although the results are limited the data showed that radii around the airguns where the received level would be 180 dB re 1 μPa (rms), the safety criterion applicable to cetaceans (NMFS, 2000), vary with water depth. Similar depth-related variation is likely in the 190 dB distances applicable to pinnipeds.

Correction factors were developed for water depths 100–1,000 m and <100 m.

The empirical data indicate that, for deep water (>1,000 m), the L-DEO model tends to overestimate the received sound levels at a given distance (Tolstoy *et al.*, 2004). However, to be precautionary pending acquisition of additional empirical data, it is proposed that safety radii during GI airgun operations in deep water will be values predicted by L-DEO's model (see Table 1 below). Therefore, the assumed 180 and 190 dB radii are 23 m (75.5 ft) and 8 m (26 ft) respectively.

Empirical measurements indicated that in shallow water (<100 m), the L-DEO model under estimates actual levels. In previous L-DEO projects, the exclusion zones were typically based on measured values and ranged from 1.3 to 15x higher than the modeled values depending on the size of the airgun array and the sound level measured (Tolstoy *et al.*, 2004). During the proposed cruise, similar factors will be applied to derive appropriate shallow water radii from the modeled deep water radii for the GI airgun (see Table 1 below).

Empirical measurements were not conducted for intermediate depths (100–1,000 m). On the expectation that results will be intermediate between those from shallow and deep water, a 1.5x correction factor is applied to the estimates provided by the model for deep water situations. This is the same factor that was applied to the model estimates during L-DEO cruises in 2003. The assumed 180 and 190 dB radii in intermediate depth water are 35 m (115 ft) and 12 m (39.4 ft), respectively (see Table 1 below).

TABLE 1. PREDICTED DISTANCES TO WHICH SOUND LEVELS ≥190, 180, AND 160 dB RE 1 μPA MIGHT BE RECEIVED IN SHALLOW (<100 M; 328 FT), INTERMEDIATE (100–1,000 M; 328–3,280 FT), AND DEEP (>1,000 M; 3,280 FT) WATER FROM THE SINGLE 45 IN^3 GI AIRGUN USED DURING THE SEISMIC SURVEYS IN THE NORTHEASTERN PACIFIC OCEAN DURING JULY 2009. DISTANCES ARE BASED ON MODEL RESULTS PROVIDED BY L-DEO.

Source and Volume	Tow Depth (m)	Water Depth	Predicted RMS Distances (m)		
			190 dB	180 dB	160 dB
Single GI airgun 45 in^3	4	Deep (>1,000 m)	8	23	220
		Intermediate (100–1,000 m)	12	35	330
		Shallow (< 100 m)	95	150	570

Proposed Dates, Duration, and Region of Activity

The *Wecoma* is scheduled to depart from Newport, Oregon, on July 14, 2009 and to return on July 20, 2009. The GI airgun will be used for approximately two hours at each of 16 OBS locations. The program will consist of approximately 7 days of seismic acquisition. The exact dates of the activities may vary by a few days because of weather conditions, repositioning, streamer operations, and adjustments, GI airgun deployment, or the need to repeat some lines if data quality is substandard. The seismic surveys will take place off the Oregon coast in the northeastern Pacific Ocean (see Figure 1 of SIO's application). The overall area within which the seismic surveys will occur is located between approximately 44° and 45° N and 124.5° and 126° W (see Figure 1 of SIO's application). The surveys will take place in water depths just less than 100 m and to almost 3,000 m, entirely within the Exclusive Economic Zone (EEZ) of the U.S.A.

Description of Marine Mammals in the Proposed Activity Area

A total of 32 marine mammal species may occur or have been documented to occur in the marine waters off Oregon and Washington, excluding extralimital sightings or strandings (Fiscus and Niggol, 1965; Green *et al.*, 1992, 1993; Barlow, 1997, 2003; Mangels and Gerrodette, 1994; Von Saunder and Barlow, 1999; Barlow and Taylor, 2001; Buchanan *et al.*, 2001; Calambokidis *et al.*, 2004; Calambokidis and Barlow, 2004). The species include 19 odontocetes (toothed cetaceans, such as dolphins), 7 mysticetes (baleen whales), 5 pinnipeds, and sea otters. Six of the species that may occur in the project area are listed under the Endangered Species Act (ESA) as Endangered, including sperm, humpback, sei, fin, blue, and North Pacific right whales. Another species, the Steller sea lion, is listed as Threatened and may occur in the project area.

The study area is located approximately 25 to 110 km (15.5 to 68.4 mi) offshore from Oregon over water depths from just less than 100 m to almost 3,000 m. Two of the 32 species, gray whales and sea otters, are not expected in the project area because their occurrence off Oregon is limited to very shallow, coastal waters. Three other species, California sea lions, Steller sea lions, and harbor seals, are mainly coastal, and would be rare at most at the OBS locations. Information on the habitat, abundance, and conservation status of the species that may occur in the study area are given in Table 2 (below, see Table 2 of SIO's application). Vagrant ringed seals, hooded seals, and ribbon seals have been sighted or stranded on the coast of California (see Mead, 1981; Reeves *et al.*, 2002) and presumably passed through Oregon waters. A vagrant beluga whale was seen off the coast of Washington (Reeves *et al.*, 2002). Those seven species are not addressed in detail in the summaries in SIO's application.

The six species of marine mammals expected to be most common in the deep pelagic or slope waters of the project area, where most of the survey sites are located, include the Pacific white-sided dolphin, northern right whale dolphin, Risso's dolphin, short beaked common dolphin, Dall's porpoise, and northern fur seal (Green *et al.*, 1992, 1993; Buchanan *et al.*, 2001; Barlow, 2003; Barlow and Forney, 2007; Carretta *et al.*, 2007). The fin whale, Dall's porpoise, and the northern elephant seal were the species sighted most often off Oregon and Washington during the ORCAWALE 2008 surveys (NMFS, 2008).

Table 2 below outlines the marine mammal species, their habitat, abundance, density, and conservation status in the proposed project area. Additional information regarding the distribution of these species expected to be found in the project area and how the estimated densities were calculated may be found in SIO's application.

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Table 2. The occurrence, habitat, regional abundance, conservation status, best and maximum density estimates, number of marine mammals that could be exposed to sound level at or above 160dB re 1μPa, best estimate of number of individuals exposed, and best estimate of number of exposures per marine mammal in or near the proposed low-energy seismic survey area in the Northeast Pacific Ocean. See Tables 2-4 in SIO's application for further detail.

Species	Habitat	Regional Population Size [e]	ESA[a]	Density/ $1000km^2$ (best) [b]	Density/ $1000km^2$ (max) [c]
Mysticetes Eastern Pacific gray whale (Eschrichtius robustus)	Coastal	17,752	NL	N.A.	N.A.
North Pacific right whale (Eubalaena japonica)	Pelagic and coastal	N.A. (Probably less than 100) [f]	EN	0	0
Humpback whale (Megaptera novaeangliae)	Mainly nearshore waters and banks	1,396	EN	0.69	1.50
Minke whale (Balaenoptera acutorostrata)	Pelagic and coastal	898	NL	0.68	1.1
Sei whale (Balaenoptera borealis)	Primarily offshore, pelagic	43	EN	0.13	0.5
Fin whale (Balaenoptera physalus)	Continental slope, mostly pelagic	3,454	EN	0.95	1.3
Blue whale (Balaenoptera musculus)	Pelagic and coastal	1,186	EN	0.19	0.4
Odontocetes Sperm whale (Physeter macrocephalus)	Usually pelagic and deep seas	2,265	EN	1.39	0.58
Pygmy sperm whale (Kogia breviceps)	Deep waters off shelf	N.A.	NL	1.24	2.8
Dwarf sperm whale (Kogia sima)	Deep waters off the shelf	N.A.	NL	0	0
Cuvier's beaked whale (Ziphius cavirostris)	Pelagic	2,171	NL	0	0
Baird's beaked whale (Berardius bairdii)	Pelagic	313	NL	1.64	0.60
Blainville's beaked whale (Mesoplodon densirostris)	Slope, offshore	1,024 [g]	NL	0	0

Hubb's beaked whale (Mesoplodon carlhubbsi)	Slope, offshore	1,024 [g]	NL	0	0
Stejneger's beaked whale (Mesoplodon stejnegeri)	Slope, offshore	1,024 [g]	NL	0	0
Offshore bottlenose dolphin (Tursiops truncatus)	Offshore, slope	3,257	NL	0	0
Striped dolphin (Stenella coeruleoalba)	Off continental shelf	23,883	NL	0.04	0.1
Short-beaked common dolphin (Delphinus delphis)	Shelf and pelagic, seamounts	487,622	NL	14.14	35
Pacific white-sided dolphin (Lagenorhynchus obliquidens)	Offshore, slope	25,233	NL	24.84	33.2
Risso's dolphin (Grampus griseus)	Shelf, slope, seamounts	12,093	NL	12.91	17.3
Northern right whale dolphin (Lissodelphis borealis)	Slope, offshore waters	15,305	NL	19.39	26.7
False killer whale (Pseudorca crassidens)	Pelagic, occasionally inshore	N.A.	NL	0	0
Killer whale (Orcinus orca)	Widely distributed	422 (Offshore)	NL	1.62	2.7
Short-finned pilot whale (Globicephala macrorhynchus)	Mostly pelagic, high-relief topography	245	NL	0	0
Harbor porpoise (Phocoena phocoena)	Coastal and inland waters	37,745 (OR/WA)	NL	N.A.	N.A.
Dall's porpoise (Phocoenoides dalli)	Shelf, slope, offshore	57,549	NL	150.17	250.9
Pinnipeds Northern fur seal (Callorhinus ursinus)	Pelagic, offshore	721,935 [f]	NL	10	100
California sea lion (Zalophus californianus)	Coastal, shelf	238,000	NL	N.A.	N.A.
Harbor seal (Phoca vitulina richardsi)	Coastal	24,732 (OR/WA)	NL	13	N.A.
Steller sea lion (Eumetopias jubatus)	Coastal, shelf	48,519 Eastern U.S. [f]	T	11	N.A.

Northern elephant seal (Mirounga angustirostris)	Coastal, pelagic when migrating	124,000 (CA)	NL	20	200

N.A. – Data not available or species status was not assessed, CA = California, OR = Oregon, WA = Washington

[a] U.S. Endangered Species Act: EN = Endangered, T = Threatened, NL = Not listed

[b] Best estimate as listed in Table 3 of the application.

[c] Maximum estimate as listed in Table 3 of the application.

[d] The numbers of at-sea sightings of California sea lions and northern elephant seals were too small to provide meaningful density estimates (Bonnell et al., 1992); density of northern elephant seals was estimated based on sightings during the ORCAWALE 2008 surveys.

[e] Abundance given for U.S. Eastern North Pacific, or CA/OR/WA stock, whichever is included in the 2007 U.S. Pacific Marine Mammal Stock Assessments (Carretta et al., 2007), unless otherwise stated.

[f] Angliss and Outlaw (2008).

[g] All mesoplodont whales.

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Potential Effects on Marine Mammals

Potential Effects of Airguns

The effects of sounds from airguns might result in one or more of the following: tolerance, masking of natural sounds, behavioral disturbances, temporary or permanent hearing impairment, and non-auditory physical or physiological effects (Richardson *et al.*, 1995; Gordon *et al.*, 2004; Nowacek *et al.*, 2007; Southall *et al.*, 2007). Permanent hearing impairment, in the unlikely event that it occurred, would constitute injury, but temporary threshold shift (TTS) is not an injury (Southall *et al.*, 2007). With the possible exception of some cases of temporary threshold shift in harbor seals, it is unlikely that the project would result in any cases of temporary or especially permanent hearing impairment, or any significant non-auditory physical or physiological effects.

Tolerance

Numerous studies have shown that pulsed sounds from airguns are often readily detectable in the water at distances of many kilometers. For a brief summary of the characteristics of airgun pulses, see Appendix A(3) of SIO's application. However, it should be noted that most of the measurements are for airguns that would be detectable considerably farther away than the GI airgun planned for use in the present project.

Several studies have shown that marine mammals at distances more than a few kilometers from operating seismic vessels often show no apparent response-see Appendix A(5) of SIO's application. That is often true even in cases when the pulsed sounds must be readily audible to the animals based on measured received levels and the hearing sensitivity of the mammal group. Although various baleen whales, toothed whales, and (less frequently) pinnipeds have been shown to react behaviorally to airgun pulses under some conditions, at other times, mammals of all three types have shown no overt reactions. In general, pinnipeds usually seem to be more tolerant of exposure to airgun pulses than are cetaceans, with relative responsiveness of baleen and toothed whales being variable. Given the relatively small and low-energy GI airgun source planned for use in this project, mammals are expected to be tolerate being closer to this source than would be the case for a larger airgun source typical of most seismic surveys.

Masking

Obscuring of sounds of interest by interfering sounds, generally at similar frequencies, is known as masking. Masking effects of pulsed sounds (even from large arrays of airguns) on marine mammal calls and other natural sounds are expected to be limited, although there are few specific data of relevance. Because of the intermittent nature and low duty cycle of seismic pulses, animals can emit and receive sounds in the relatively quiet intervals between pulses. However in some situations, multi-path arrivals and reverberation cause airgun sound to arrive for much or all of the interval between pulses (Simard *et al.*, 2005; Clark and Gagnon, 2006), which could mask calls. Some baleen and toothed whales are known to continue calling in the presence of seismic pulses. The airgun sounds are pulsed, with quiet periods between the pulses, and whale calls often can be heard between the seismic pulses (Richardson *et al.*, 1986; McDonald *et al.*, 1995; Greene *et al.*, 1999; Nieukirk *et al.*, 2004; Smultea *et al.*, 2004; Holst *et al.*, 2005a,b, 2006). In the northeast Pacific Ocean, blue whale calls have been recorded during a seismic survey off Oregon (McDonald *et al.*, 1995). Among odontocetes, there has been one report that sperm whales cease calling when exposed to pulses from a very distant seismic ship (Bowles *et al.*, 1994). However, more recent studies found that sperm whales continued calling in the presence of seismic pulses (Madsen *et al.*, 2002; Tyack *et al.*, 2003; Smultea *et al.*, 2004; Holst *et al.*, 2006; Jochens *et al.*, 2006, 2008). Given the small source planned for use during the proposed survey, there is even less potential for masking of baleen or sperm whale calls during the present study than in most seismic surveys. Masking effects of seismic pulses are expected to be negligible in the case of the small odontocetes given the intermittent nature of seismic pulses. Dolphins and porpoises commonly are heard calling while airguns are operating (Gordon *et al.*, 2004; Smultea *et al.*, 2004; Holst *et al.*, 2005a,b; Potter *et al.*, 2007). Also, the sounds important to small odontocetes are predominantly at much higher frequencies than the airgun sounds, thus further limiting the potential for masking. In general, masking effects of seismic pulses are expected to be minor, given the normally intermittent nature of seismic pulses. Masking effects on marine mammals are discussed further in Appendix A (4) of SIO's application.

Disturbance Reactions

Disturbance includes a variety of effects, including subtle changes in behavior, more conspicuous changes in activities, and displacement. Reactions to sound, if any, depend on species, state of maturity, experience, current activity, reproductive state, time of day, and many other factors. If a marine mammal responds to an underwater sound by changing its behavior or moving a small distance, the response may or may not rise to the level of ''harassment,'' or affect the stock or the species as a whole. However, if a sound source displaces marine mammals from an important feeding or breeding area for a prolonged period, impacts on animals or on the stock or species could potentially be significant (Lusseau and Bejder, 2007). Given the many uncertainties in predicting the quantity and types of impacts of noise on marine mammals, it is common practice to estimate how many mammals are likely to be present within a particular distance of industrial activities, or exposed to a particular level of industrial sound. This practice potentially overestimates the numbers of marine mammals that are affected in some biologically-important manner.

The sound exposure thresholds that are used to estimate how many marine mammals might be harassed by a seismic survey are based on behavioral observations during studies of several species. However, information is lacking for many species. Detailed studies have been done on humpback, gray, bowhead, and on ringed seals. Less detailed data are available for some other species of baleen whales, sperm whales, small toothed whales, and sea otters, but for many species there are no data on responses to marine seismic surveys. Most of those studies have concerned reactions to much larger airgun sources than planned for use in the proposed project. Thus, effects are expected to be limited to considerably smaller distances and shorter periods of exposure in the present project than in most of the previous work concerning marine mammal reactions to airguns.

Baleen Whales – Baleen whales generally tend to avoid operating airguns, but avoidance radii are quite variable. Whales are often reported to show no overt reactions to pulses from large arrays of airguns at distances beyond a few kilometers, even though the airgun pulses remain well above ambient noise levels out to much longer distances. However, as reviewed in Appendix A(5) of SIO's application, baleen whales exposed to strong noise pulses from airguns often react by deviating from their normal migration route and/or interrupting their feeding activities and moving away from the sound source. In the case of the migrating gray and bowhead whales, the observed changes in behavior appeared to be of little or no biological consequence to the animals. They simply avoided the sound source by displacing their migration route to varying degrees, but within the natural boundaries of the migration corridors.

Studies of gray, bowhead, and humpback whales have demonstrated that received levels of pulses in the 160–170 dB re 1 μPa rms range seem to cause obvious avoidance behavior in a substantial fraction of the animals exposed. In many areas, seismic pulses from large arrays of airguns diminish to those levels at distances ranging from 4.5–14.5 km (2.8–9 mi) from the source. A substantial proportion of the baleen whales within those distances may show avoidance or other strong disturbance reactions to the airgun array. Subtle behavioral changes sometimes become evident at somewhat lower received levels, and studies summarized in Appendix A(5) of SIO's application have shown that some species of baleen whales, notably bowhead and humpback whales, at times show strong avoidance at received levels lower than 160–170 dB re 1 μPa (rms). Reaction distances would be considerably smaller during the proposed project, for which the 160 dB radius is predicted to be 220 to 570 m (722 to 1,870 ft) (see Table 1 above), as compared with several km when a large array of airguns is operating.

Responses of humpback whales to seismic surveys have been studied during migration, on the summer feeding grounds, and on Angolan winter breeding grounds; there has also been discussion of effects on the Brazilian wintering grounds. McCauley *et al.* (1998, 2000a) studied the responses of humpback whales off Western Australia to a full-scale seismic survey with a 16–airgun, 2,678 in^3 array, and to a single 20 in^3 airgun with a source level of 227 dB re 1 μPa m peak-to-peak. McCauley *et al.* (1998) documented that initial avoidance reactions began at 5 to 8 km (3.1 to 5 mi) from the array, and that those reactions kept most pods approximately 3 to 4 km (1.9 to 2.5 mi) from the operating seismic boat. McCauley *et al.* (2000) noted localized displacement during migration of 4 to 5 km (2.5 to 3.1 mi) by traveling pods and 7 to12 km (4.3 to 7.5 mi) by cow-calf pairs. Avoidance distances with respect to the single airgun were smaller (2 km (1.2 mi)) but consistent with the results from the full array in terms of received sound levels. The mean received level for initial avoidance reactions of an approaching airgun was a sound level of 140 dB re 1 μPa (rms) for humpback whale pods containing females. The standoff range, i.e., the closest point of approach (CPA) of the whales to the airgun, corresponded to a received level of 143 dB re 1 μPa (rms). The initial avoidance response generally occurred at distances of 5 to 8 km (3.1 to 5 mi) from the airgun array and 2 km (1.2 mi) from the single airgun. However, some individual humpback whales, especially males, approached within distances of 100 to 400 m (328 to 1,312 ft), where the maximum received level was 179 dB re 1 μPa (rms).

Humpback whales on their summer feeding grounds in southeast Alaska did not exhibit persistent avoidance when exposed to seismic pulses from a 1.64–L (100 in^3) airgun (Malme *et al.*, 1985). Some humpbacks seemed ''startled'' at received levels of 150–169 dB re 1 μPa on an approximate rms basis. Malme *et al.* (1985) concluded that there was no clear evidence of avoidance, despite the possibility of subtle effects, at received levels up to 172 re 1 μPa on an approximate rms basis.

Among wintering humpback whales off Angola (n = 52 useable groups), there were no significant differences in encounter rates (sightings/hr) when a 24 airgun array (3,147 in^3 or 5,805 in^3) was operating vs. silent (Weir, 2008). There was also no significant difference in the mean CPA distance of the humpback whale sightings when airguns were on vs. off (3,050 m vs. 2,700 m or 10,007 vs. 8,858 ft, respectively).

It has been suggested that South Atlantic humpback whales wintering off Brazil may be displaced or even strand upon exposure to seismic surveys (Engel *et al.*, 2004). The evidence for this was circumstantial and subject to alternative explanations (IAGC, 2004). Also, the evidence was not consistent with subsequent results from the same area of Brazil (Parente *et al.*, 2006), or with results from direct studies of humpbacks exposed to seismic surveys in other areas and seasons. After allowance for data from subsequent years, there was ''no observable direct correlation'' between strandings and seismic surveys (IWC, 2007b:236).

There are no data on reactions of right whales to seismic surveys, but results from the closely-related bowhead whale show that their responsiveness can be quite variable depending on the activity (e.g., migrating vs. feeding). Bowhead whales migrating west across the Alaskan Beaufort Sea in autumn, in particular, are unusually responsive, with substantial avoidance occurring out to distances of 20–30 km (12.4–18.6 mi) from a medium-sized airgun source at received sound levels of around 120–130 dB re 1 μPa (rms) (Miller *et al.*, 1999; Richardson *et al.*, 1999; see Appendix B (5) of L-DEO's application). However, more recent research on bowhead whales (Miller *et al.*, 2005a; Harris *et al.*, 2007) corroborates earlier evidence that, during the summer feeding season, bowheads are not as sensitive to seismic sources. Nonetheless, subtle but statistically significant changes in surfacing-respiration-dive cycles were evident upon statistical analysis (Richardson *et al.*, 1986). In summer, bowheads typically begin to show avoidance reactions at a received level of about 160–170 dB re 1 μPa (rms) (Richardson *et al.*, 1986; Ljungblad *et al.*, 1988; Miller *et al.*, 2005a).

Reactions of migrating and feeding (but not wintering) gray whales to seismic surveys have been studied. Malme *et al.* (1986, 1988) studied the responses of feeding Eastern Pacific gray whales to pulses from a single 100 in^3 airgun off St. Lawrence Island in the northern Bering Sea. Malme *et al.* (1986, 1988) estimated, based on small sample sizes, that 50 percent of feeding gray whales ceased feeding at an average received pressure level of 173 dB re 1 μPa on an (approximate) rms basis, and that 10 percent of feeding whales interrupted feeding at received levels of 163 dB. Those findings were generally consistent with the results of experiments conducted on larger numbers of gray whales that were migrating along the California coast (Malme *et al.*, 1984; Malme and Miles, 1985), and with observations of Western Pacific gray whales feeding off Sakhalin Island, Russia, when a seismic survey was underway just offshore of their feeding area (Gailey *et al.*, 2007; Johnson *et al.*, 2007; Yazvenko *et al.* 2007a,b), along with data on gray whales off British Columbia (Bain and Williams, 2006). Gray whales typically show no conspicuous responses to airgun pulses with received levels up to 150 to 160 dB re 1 μPa (rms), but are increasingly likely to show avoidance as received levels increase above that range.

Various species of *Balaenoptera* (blue, sei, fin, Bryde's, and minke whales) have occasionally been reported in areas ensonified by airgun pulses (Stone, 2003; MacLean and Haley, 2004; Stone and Tasker, 2006). Sightings by observers on seismic vessels off the United Kingdom from 1997 to 2000 suggest that, at times of good sightability, sighting rates for mysticetes (mainly fin and sei whales) were similar when large arrays of airguns were shooting and not shooting (Stone, 2003; Stone and Tasker, 2006). However, these whales tended to exhibit localized avoidance, remaining significantly (on average) from the airgun array during seismic operations compared with non-seismic periods (Stone and Tasker, 2006). In a study off Nova Scotia, Moulton and Miller (2005) found little difference in sighting rates (after accounting for water depth) and initial sighting distances of balaenopterid whales when airguns were operating vs. silent. However, there were indications that these whales were more likely to be moving away when seen during airgun operations. Similarly, ship-based monitoring studies of blue, fin, sei, and minke whales offshore of Newfoundland (Orphan Basin and Laurentian Sub-basin) found no more than small differences in sighting rates and swim direction during seismic vs. non-seismic periods (Moulton *et al.*, 2005, 2006a,b).

Data on short-term reactions (or lack of reactions) of cetaceans to impulsive noises do not necessarily provide information about long-term effects. It is not known whether impulsive noises affect reproductive rate or distribution and habitat use in subsequent days or years. However, gray whales continued to migrate annually along the west coast of North America with substantial increases in the population over recent years, despite intermittent seismic exploration and much ship traffic in that area for decades (see Appendix A in Malme *et al.*, 1984; Richardson *et al.*, 1995; Angliss and Outlaw, 2008). The Western Pacific gray whale population did not seem affected by a seismic survey in its feeding ground during a prior year (Johnson *et al.*, 2007). Bowhead whales continued to travel to the eastern Beaufort Sea each summer, and their numbers have increased notably, despite seismic exploration in their summer and autumn range for many years (Richardson *et al.*, 1987). In any event, brief exposures to sound pulses from the proposed airgun source are highly unlikely to result in prolonged effects.

Toothed Whales – Little systematic information is available about reactions of toothed whales to noise pulses. Few studies similar to the more extensive baleen whale/seismic pulse work summarized above have been reported for toothed whales. However, systematic studies on sperm whales have been done (Jochens and Biggs, 2003; Tyack *et al.*, 2003; Jochens *et al.*, 2006; Miller *et al.*, 2006), and there is an increasing amount of information about responses of various odontocetes to seismic surveys based on monitoring studies (Stone, 2003; Smultea *et al.*, 2004; Moulton and Miller, 2005; Bain and Williams, 2006; Holst *et al.*, 2006; Stone and Tasker, 2006; Potter *et al.*, 2007; Weir, 2008).

Seismic operators and MMOs on seismic vessels regularly see dolphins and other small toothed whales near operating airgun arrays, but in general there seems to be a tendency for most delphinids to show some avoidance of operating seismic vessels (Goold, 1996a,b,c; Calambokidis and Osmek, 1998; Stone, 2003; Moulton and Miller, 2005; Holst *et al.*, 2006; Stone and Tasker, 2006; Weir, 2008). Some dolphins seem to be attracted to the seismic vessel and floats, and some ride the bow wave of the seismic vessel even when large airgun arrays are firing (Moulton and Miller, 2005). Nonetheless, there have been indications that small toothed whales sometimes tend to head away or to maintain a somewhat greater distance from the vessel, when a large array of airguns is operating than when it is silent (Stone and Tasker, 2006; Weir, 2008). In most cases, the avoidance radii for delphinids appear to be small, on the order of 1 km (0.62 mi) or less, and some individuals show no apparent avoidance. The beluga is a species that (at least at times) shows long-distance avoidance of seismic vessels. Aerial surveys during seismic operations in the southeastern Beaufort Sea during summer recorded much lower sighting rates of beluga whales within 10–20 km (6.2–12.4 mi) compared with 20–30 km (mi) from an operating airgun array, and observers on seismic boats in that area rarely see belugas (Miller *et al.*, 2005a; Harris *et al.*, 2007).

Captive bottlenose dolphins and beluga whales exhibited changes in behavior when exposed to strong pulsed sounds similar in duration to those typically used in seismic surveys (Finneran *et al.*, 2000, 2002, 2005; Finneran and Schlundt, 2004). The animals tolerated high received levels of sound (pk-pk level >200 dB re 1 μPa) before exhibiting aversive behaviors. For pooled data at 3, 10, and 20 kHz, sound exposure levels during sessions with 25, 50, and 75 percent altered behavior were 180, 190, and 199 dB re 1 μPa^2, respectively (Finneran and Schlundt, 2004).

Results for porpoises depend on species. Dall's porpoises seem relatively tolerant of airgun operations (MacLean and Koski, 2005) and, during a survey with a large airgun array, tolerated higher noise levels than did harbor porpoises and gray whales (Bain and Williams, 2006). However, Dall's porpoises do respond to the approach of large airgun arrays by moving away (Calambokidis and Osmek, 1998; Bain and Williams, 2006). The limited available data suggest that harbor porpoises show stronger avoidance (Stone, 2003; Bain and Williams, 2006; Stone and Tasker, 2006). This apparent difference in responsiveness of these two porpoise species is consistent with their relative responsiveness to boat traffic and some other acoustic sources in general (Richardson *et al.*, 1995; Southall *et al.* 2007).

Most studies of sperm whales exposed to airgun sounds indicate that this species shows considerable tolerance of airgun pulses (Stone, 2003; Moulton *et al.*, 2005, 2006a; Stone and Tasker, 2006; Weir, 2008). In most cases, the whales do not show strong avoidance and continue to call (see Appendix A in SIO's application). However, controlled exposure experiments in the Gulf of Mexico indicate that foraging effort is somewhat altered upon exposure to airgun sounds (Jochens *et al.*, 2006, 2008). In the SWSS study, D-tags (Johnson and Tyack, 2003) were used to record the movement and acoustic exposure of eight foraging sperm whales before, during, and after controlled sound exposures of airgun arrays in the Gulf of Mexico (Jochens *et al.*, 2008). Whales were exposed to maximum received sound levels between 111 and 147 dB re 1 μPa (rms) (131 to 164 dB re 1 μPa pk-pk) at ranges of approximately 1.4 to 12. 6 km (0.9 to 7.8 mi) from the sound source. Although the tagged whales showed no horizontal avoidance, some whales changed foraging behavior during full array exposure (Jochens *et al.*, 2008).

There are almost no specific data on the behavioral reactions of beaked whales to seismic surveys. However, northern bottlenose whales (*Hyperodon ampullatus*) continued to produce high-frequency clicks when exposed to sound pulses from distant seismic surveys (Laurinolli and Cochrane, 2005; Simard *et al.*, 2005). Most beaked whales tend to avoid approaching vessels of other types (Wursig *et al.*, 1998). They may also dive for an extended period when approached by a vessel (Kasuya, 1986), although it is uncertain how much longer such dives may be as compared to dives by undisturbed beaked whales, which also are often quire long (Baird *et al.*, 2006; Tyack *et al.*, 2006). In any event, it is likely that these beaked whales would normally show strong avoidance of an approaching seismic vessel, but this has not been documented explicitly.

Odontocete reactions to large arrays of airguns are variable and, at least for delphinids and Dall's porpoises, seem to be confined to a smaller radius than has been observed for the more responsive of the mysticetes, belugas, and harbor porpoises (Appendix A of SIO's application).

Additional details on the behavioral reactions (or the lack thereof) by all types of marine mammals to seismic vessels can be found in Appendix A(5) of SIO's application.

Hearing Impairment and Other Physical Effects

Temporary or permanent hearing impairment is a possibility when marine mammals are exposed to very strong sounds, but there has been no specific documentation of this for marine mammals exposed to sequences of airgun pulses.

NMFS will be developing new noise exposure criteria for marine mammals that take account of the now-available scientific data on temporary threshold shift (TTS), the expected offset between the TTS and permanent threshold shift (PTS) thresholds, differences in the acoustic frequencies to which different marine mammal groups are sensitive, and other relevant factors. Detailed recommendations for new science-based noise exposure criteria were published in late 2007 (Southall *et al.*, 2007).

Several aspects of the planned monitoring and mitigation measures for this project (see below) are designed to detect marine mammals occurring near the airguns to avoid exposing them to sound pulses that might, at least in theory, cause hearing impairment. In addition, many cetaceans and (to a limited degree) pinnipeds are likely to show some avoidance of the area where received levels of airgun sound are high enough such that hearing impairment could potentially occur. In those cases, the avoidance responses of the animals themselves will reduce or (most likely) avoid any possibility of hearing impairment.

Non-auditory physical effects may also occur in marine mammals exposed to strong underwater pulsed sound. Possible types of non-auditory physiological effects or injuries that theoretically might occur in mammals close to a strong sound source include stress, neurological effects, bubble formation, resonance effects, and other types of organ or tissue damage. It is possible that some marine mammal species (i.e., beaked whales) may be especially susceptible to injury and/or stranding when exposed to strong pulsed sounds. However, as discussed below, there is no definitive evidence that any of these effects occur even for marine mammals in close proximity to large arrays of airguns. It is especially unlikely that any effects of these types would occur during the present project given the brief duration of exposure of any given mammal and the proposed monitoring and mitigation measures (see below). The following subsections discuss in somewhat more detail the possibilities of TTS, PTS, and non-auditory physical effects.

Temporary Threshold Shift – TTS is the mildest form of hearing impairment that can occur during exposure to a strong sound (Kryter, 1985). While experiencing TTS, the hearing threshold rises and a sound must be stronger in order to be heard. At least in terrestrial mammals, TTS can last from minutes or hours to (in cases of strong TTS) days. For sound exposures at or somewhat above the TTS threshold, hearing sensitivity in both terrestrial and marine mammals recovers rapidly after exposure to the noise ends. Few data on sound levels and durations necessary to elicit mild TTS have been obtained for marine mammals, and none of the published data concern TTS elicited by exposure to multiple pulses of sound. Available data on TTS in marine mammals are summarized in Southall *et al.* (2007).

For toothed whales exposed to single short pulses, the TTS threshold appears to be, to a first approximation, a function of the energy content of the pulse (Finneran *et al.*, 2002, 2005). Given the available data, the received level of a single seismic pulse (with no frequency weighting) might need to be approximately 186 dB re 1 $\mu Pa^2 \cdot s$ (i.e., 186 dB SEL or approximately 221–226 dB pk-pk) in order to produce brief, mild TTS. Exposure to several strong seismic pulses that each have received levels near 190 dB re 1 μPa (rms) (175–180 dB SEL) might result in cumulative exposure of approximately 186 dB SEL and thus slight TTS in a small odontocete, assuming the TTS threshold is (to a first approximation) a function of the total received pulse energy. Levels ≥ 190 dB 1 μPa (rms) are expected to be restricted to radii no more than 95 m (312 ft) from the *Wecoma*'s GI airgun. For an odontocete closer to the surface, the maximum radius with ≥190 dB 1 μPa (rms) would be smaller.

The above TTS information for odontocetes is derived from studies on the bottlenose dolphin and beluga. There is not published TTS information for other species of cetaceans. However, preliminary evidence from harbor porpoise exposed to airgun sound suggests that its TTS threshold may have been lower (Lucke *et al.*, 2007).

For baleen whales, there are no data, direct or indirect, on levels or properties of sound required to induce TTS. The frequencies to which baleen whales are most sensitive are lower than those for odontocetes, and natural background noise levels at those low frequencies tend to be higher. As a result, auditory thresholds of baleen whales within their frequency band of best hearing are believed to be higher (less sensitive) than are those of odontocetes at their best frequencies (Clark and Ellison, 2004). From this, it is suspected that received levels causing TTS onset may also be higher in baleen whales. In any event, no cases of TTS are expected given three considerations:

(1) Small size of the GI airgun source;

(2) The strong likelihood that baleen whales would avoid the approaching airguns (or vessel) before being exposed to levels high enough for TTS to possibly occur; and

(3) The mitigation measures that are planned.

In pinnipeds, TTS thresholds associated with exposure to brief pulses (single or multiple) of underwater sound have not been measured. Initial evidence from prolonged (non-pulse) exposures suggested that some pinnipeds may incur TTS at somewhat lower received levels than do small odontocetes exposed for similar durations (Kastak *et al*., 1999, 2005; Ketten *et al*., 2001; Au *et al*., 2000). The TTS threshold for pulsed sounds has been indirectly estimated as being an SEL of approximately 171 dB re 1 μPa^2·s (Southall *et al*., 2007), which would be equivalent to a single pulse with received level approximately 181–186 re 1 μPa (rms), or a series of pulses for which the highest rms values are a few dB lower. Corresponding values for California sea lions and northern elephant seals are likely to be higher (Kastak *et al*., 2005).

A marine mammal within a radius of less than 100 m (328 ft) around a typical large array of operating airguns might be exposed to a few seismic pulses with levels of greater than or equal to 205 dB, and possibly more pulses if the mammal moved with the seismic vessel. (As noted above, most cetacean species tend to avoid operating airguns, although not all individuals do so.) In addition, ramping up airgun arrays, which is standard operational protocol for large airgun arrays and proposed for this action, should allow cetaceans to move away form the seismic source and avoid being exposed to the full acoustic output of the airgun array. Even with a large airgun array, it is unlikely that the cetaceans would be exposed to airgun pulses at a sufficiently high level for a sufficiently long period to cause more than mild TTS, given the relative movement of the vessel and the marine mammal. The potential for TTS is much lower in this project. With a large array of airguns, TTS would be most likely in any odontocetes that bow-ride or otherwise linger near the airguns. While bow-riding, odontocetes would be at or above the surface, and thus not exposed to strong pulses given the pressure-release effect at the surface. However, bow-riding animals generally dive below the surface intermittently. If they did so while bow-riding near airguns, they would be exposed to strong sound pulses, possibly repeatedly. If some cetaceans did incur TTS through exposure to airgun sounds, this would very likely be mild, temporary, and reversible.

To avoid the potential for injury, NMFS has determined that cetaceans and pinnipeds should not be exposed to pulsed underwater noise at received levels exceeding, respectively, 180 and 190 dB re 1 μPa (rms). As summarized above, data that are now available imply that TTS is unlikely to occur unless odontocetes (and probably mysticetes as well) are exposed to airgun pulses stronger than 180 dB re 1 μPa (rms).

Permanent Threshold Shift – When PTS occurs, there is physical damage to the sound receptors in the ear. In severe cases, there can be total or partial deafness, while in other cases, the animal has an impaired ability to hear sounds in specific frequency ranges (Kryter, 1985).

There is no specific evidence that exposure to pulses of airgun sound can cause PTS in any marine mammal, even with large arrays of airguns. However, given the possibility that mammals close to an airgun array might incur TTS, there has been further speculation about the possibility that some individuals occurring very close to airguns might incur PTS (Richardson *et al*., 1995). Single or occasional occurrences of mild TTS are not indicative of permanent auditory damage.

Relationships between TTS and PTS thresholds have not been studied in marine mammals, but are assumed to be similar to those in humans and other terrestrial mammals. PTS might occur at a received sound level at least several decibels above that inducing mild TTS if the animal were exposed to strong sound pulses with rapid rise time (see Appendix A(5) of SIO's application). Based on data from terrestrial mammals, a precautionary assumption is that the PTS threshold for impulse sounds (such as airgun pulses as received close to the source) is at least 6 dB higher than the TTS threshold on a peak-pressure basis, and probably >6 dB (Southall *et al*., 2007). On an SEL basis, Southall *et al.* (2007) estimated that received levels would need to exceed the TTS threshold by at least 15 dB for there to be risk of PTS. Thus, for cetaceans they estimate that the PTS threshold might be an M-weighted SEL (for the sequence of received pulses) of approximately 198 dB re 1 μPa^{2}μs (15 dB higher than the TTS threshold for an impulse). Additional assumptions had to be made to derive a corresponding estimate for pinnipeds, as the only available data on TTS thresholds in pinnipeds pertain to non-impulse sound. Southall *et al.* (2007) estimate that the PTS threshold could be a cumulative Mpw-weighted SEL of approximately 186 dB 1 μPa^2·s in the harbor seal to impulse sound. The PTS threshold for the California sea lion and northern elephant seal the PTS threshold would probably be higher, given the higher TTS thresholds in those species.

Southall *et al.* (2007) also note that, regardless of the SEL, there is concern about the possibility of PTS if a cetacean or pinniped receives one or more pulses with peak pressure exceeding 230 or 218 dB re 1 μPa (3.2 bar· m, 0–pk), which would only be found within a few meters of the largest (600–in^3) airguns in the planned airgun array (Caldwell and Dragoset, 2000). A peak pressure of 218 dB re 1 μPa could be received somewhat farther away; to estimate that specific distance, one would need to apply a model that accurately calculates peak pressures in the near-field around an array of airguns.

Given the higher level of sound necessary to cause PTS as compared with TTS, it is considerably less likely that PTS could occur. Baleen whales generally avoid the immediate area around operating seismic vessels, as do some other marine mammals. The planned monitoring and mitigation measures, including visual monitoring and shut downs of the airguns when mammals are seen about to enter or within the proposed exclusion zone (EZ), will further reduce the probability of exposure of marine mammals to sounds strong enough to induce PTS, see the section below on Proposed Mitigation and Monitoring.

Non-auditory Physiological Effects – Non-auditory physiological effects or injuries that theoretically might occur in marine mammals exposed to strong underwater sound include stress, neurological effects, bubble formation, resonance effects, and other types of organ or tissue damage (Cox *et al*., 2006; Southall *et al*., 2007). Studies examining such effects are limited. However, resonance (Gentry, 2002) and direct noise-induced bubble formation (Crum *et al*., 2005) are not expected in the case of an impulsive source like an airgun array. If seismic surveys disrupt diving patterns of deep diving species, this might perhaps result in bubble formation and a form of ''the bends,'' as speculated to occur in beaked whales exposed to sonar. However, there is no specific evidence of this upon exposure to airgun pulses.

In general, little is known about the potential for seismic survey sounds to cause auditory impairment or other physical effects in marine mammals. Available data suggest that such effects, if they occur at all, would presumably be limited to short distances from the sound source and to activities that extend over a prolonged period. The available data do not allow identification of a specific exposure level above which non-auditory effects can be expected (Southall *et al*., 2007), or any meaningful quantitative predictions of the numbers (if any) of marine mammals that might be affected in those ways. Marine mammals that show behavioral avoidance of seismic vessels, including most baleen whales, some odontocetes, and some pinnipeds, are especially unlikely to incur auditory impairment or non-auditory physical effects. Also, the planned mitigation measures, including shut downs of the airgun, would reduce any such effects that might otherwise occur.

Strandings and Mortality

Marine mammals close to underwater detonations of high explosives can be killed or severely injured, and their auditory organs are especially susceptible to injury (Ketten *et al*., 1993; Ketten, 1995). However, explosives are no longer used for marine seismic research or commercial seismic surveys, and have been replaced entirely by airguns or related non-explosive pulse generators. Airgun pulses are less energetic and have slower rise times, and there is no specific evidence that they can cause injury, death, or stranding even in the case of large airgun arrays. However, the association of mass strandings of beaked whales with naval exercises and, in one case, an L-DEO seismic survey (Malakoff, 2002; Cox *et al*., 2006), has raised the possibility that beaked whales exposed to strong ''pulsed'' sounds may be especially susceptible to injury and/or behavioral reactions that can lead to stranding (Hildebrand, 2005; Southall *et al*., 2007). Appendix A(5) of SIO's application provides additional details.

Specific sound-related processes that lead to strandings and mortality are not well documented, but may include:

(1) Swimming in avoidance of a sound into shallow water;

(2) A change in behavior (such as a change in diving behavior) that might contribute to tissue damage, gas bubble formation, hypoxia, cardiac arrhythmia, hypertensive hemorrahage or other forms of trauma;

(3) A physiological change such as a vestibular response leading to a behavioral change or stress-induced hemorrahagic diathesis, leading in turn to tissue damage; and

(4) Tissue damage directly from sound exposure, such as through acoustically mediated bubble formation and growth or acoustic resonance of tissues.

As noted in SIO's application, some of these mechanisms are unlikely to apply in the case of impulse sounds. However, there are increasing indications that gas-bubble disease (analogous to ''the bends''), induced in super-saturated tissue by a behavioral response to acoustic exposure, could be pathologic mechanism for the strandings and mortality of some deep diving cetaceans exposed to sonar. The evidence for this remains circumstantial and associated with exposure to naval mid-frequency sonar, not seismic surveys (Cox *et al*., 2006; Southall *et al*., 2007).

Seismic pulses and mid-frequency sonar pulses are quite different, and some mechanisms by which sonar sounds have been hypothesized to affect beaked whales are unlikely to apply to airgun pulses. Sounds produced by airgun arrays are broadband with most of the energy below 1 kHz. Typical military mid-frequency sonars operate at frequencies of 2–10 kHz, generally with a relatively narrow bandwidth at any one time. A further difference between seismic surveys and naval exercises is that naval exercises can involve sound sources on more than one vessel. Thus, it is not appropriate to assume that there is a direct connection between the effects of military sonar and seismic surveys on marine mammals. However, evidence that sonar pulses can, in special circumstances, lead (at least indirectly) to physical damage and mortality (Balcomb and Claridge, 2001; NOAA and USN, 2001; Jepson *et al*., 2003; Fernandez *et al*., 2004, 2005a,b; Hildebrand, 2005; Cox *et al*., 2006) suggests that caution is warranted when dealing with exposure of marine mammals to any high-intensity pulsed sound.

There is no conclusive evidence of cetacean strandings or deaths at sea as a result of exposure to seismic surveys, but a few cases of strandings in the general area where a seismic survey was ongoing have led to speculation concerning a possible link between seismic surveys and strandings. Suggestions that there was a link between seismic surveys and strandings of humpback whales in Brazil (Engel *et al*., 2004) was not well founded based on available data (IAGC, 2004; IWC, 2006). In September 2002, there was a stranding of two Cuvier's beaked whales (*Ziphius cavirostris*) in the Gulf of California, Mexico, when the L-DEO vessel R/V *Maurice Ewing* (*Ewing*) was operating a 20–gun, 8,490–in^3 array in the general area. The link between the stranding and the seismic survey was inconclusive and not based on any physical evidence (Hogarth, 2002; Yoder, 2002). Nonetheless, the Gulf of California incident plus the beaked whale strandings near naval exercises involving use of mid-frequency sonar suggests a need for caution when conducting seismic surveys in areas occupied by beaked whales until more is known about effects of seismic surveys on those species (Hildebrand, 2005).

No injuries of beaked whales are anticipated during the proposed study because of (1) the high likelihood that any beaked whales nearby would avoid the approaching vessel before being exposed to high sound levels, (2) the proposed monitoring and mitigation measures, including avoiding submarine canyons, where deep diving species may congregate, and (3) differences between the sound sources operated by SIO and those involved in the naval exercises associated with strandings.

Potential Effects of Other Acoustic Devices

Sub-bottom Profiler Signals

A SBP will be operated from the source vessel at all times during the planned study. Sounds from the SBP are very short pulses, occurring for 12 or 24 ms once every 4.5 to 8 seconds. Most of the energy in the sound pulses emitted by the SBP is at mid frequencies, centered at 3.5 kHz. The beamwidth is approximately 80° and is directed downward.

The SBP on the *Wecoma* has a maximum source level of 211 dB re 1 μPam. Thus the received level would be expected to decrease to 180 dB and 160 dB approximately 35 m (115 ft) and 350 m (1,148 ft) below the transducer, respectively, assuming spherical spreading. Corresponding distances in the horizontal plane would be substantially lower, given the directionality of this source. Kremser *et al.* (2005) noted that the probability of a cetacean swimming through the area of exposure when a bottom profiler emits a pulse is small, and if the animal was in the area, it would have to pass the transducer at close range in order to be subjected to sound levels that could cause TTS.

Marine mammal communications will not be masked appreciably by the SBP signals given their directionality and the brief period when an individual mammal is likely to be within its beam. Furthermore, in the case of most odontocetes, the signals do not overlap with the predominant frequencies in the calls, which would avoid significant masking.

Marine mammal behavioral reactions to other pulsed sound sources are discussed above, and responses to the SBP are likely to be similar to those for other pulsed sources if received at the same levels. Therefore, behavioral responses are not expected unless marine mammals are very close to the source.

The source levels of the SBP are much lower than those of the airgun. It is unlikely that the SBP produces pulse levels strong enough to cause hearing impairment or other physical injuries even in an animal that is (briefly) in a position near the source. The SBP is usually operated simultaneously with other higher-power acoustic sources. Many marine mammals will move away in response to the approaching higher-power sources or the vessel itself before the mammals would be close enough for there to be any possibility of effects from the less intense sounds from the SBP. In the case of mammals that do not avoid the approaching vessel and its various sound sources, mitigation measures that would be applied to minimize effects of other sources would further reduce or eliminate any minor effects of the SBP.

As stated above, NMFS is assuming that Level A harassment onset corresponds to 180 and 190 dB re 1 μPa (rms) for cetaceans and pinnipeds, respectively. The precautionary nature of these criteria is discussed in Appendix A(5) of SIO's application, including the fact that the minimum sound level necessary to cause permanent hearing impairment is higher, by a variable and generally unknown amount, than the level that induces barely-detectable TTS and the level associated with the onset of TTS is often considered to be a level below which there is no danger of permanent damage. NMFS also assumes that cetaceans or pinnipeds exposed to levels exceeding 160 dB re 1 μPa (rms) may experience Level B harassment.

Possible Effects of Acoustic Release Signals

The acoustic release transponder used to communicate with the OBSs uses frequencies of 9–13 kHz. Once the OBS is ready to be retrieved, an acoustic release transponder interrogates the OBS at a frequency of 9–11 kHz, and a response is received at a frequency of 9–13 kHz. The burn wire release is then activated, and the instrument is released from the anchor to float to the surface. These signals will be used very intermittently. It is unlikely that the acoustic release signals would have effects on marine mammals through masking, disturbance, or hearing impairment. Any effects likely would be de minimus given the brief exposure at low levels.

Estimated Take by Incidental Harassment

All anticipated takes would be ''takes by harassment,'' involving temporary changes in behavior. The proposed monitoring and mitigation measures are expected to minimize the possibility of injurious takes. (However, as noted earlier, there is no specific information demonstrating that injurious ''takes'' would occur even in the absence of the planned monitoring and mitigation measures.) The sections below describe methods to estimate ''take by harassment'', and present estimates of the numbers of marine mammals that might be affected during the proposed seismic program. The estimates of ''take by harassment'' are based on (1) data concerning marine mammal densities (numbers per unit area) obtained during surveys off Oregon and Washington during 1996, 2001, and 2005 (cetaceans), or 1989 to 1990 (pinnipeds) by NMFS Southwest Fisheries Science Center (SWFSC), and (2) estimates of the size of the 160 dB isolpeths where takes could potentially occur from the proposed seismic survey off the coast of Oregon in the northeastern Pacific Ocean.

Extensive systematic aircraft and ship-based surveys have been conducted for marine mammals offshore of Oregon and Washington (Bonnell *et al.*, 1992; Green *et al.*, 1992, 1993; Barlow 1997, 2003; Barlow and Taylor, 2001; Calambokidis and Barlow, 2004; Barlow and Forney in prep.). The most comprehensive and recent density data available for cetacean species in slope and offshore waters of Oregon are from the 1996, 2001, and 2005 NMFS SWFSC ''ORCAWALE'' or ''CSCAPE'' ship surveys as synthesized by Barlow and Forney (2007). The surveys were conducted up to approximately 550 km (342 mi) offshore from June or July to November or December. Systematic, offshore, at-sea survey data for pinnipeds are more limited. The most comprehensive such studies are reported by Bonnell *et al.* (1992) based on systematic aerial surveys conducted in 1989–1990.

Oceanographic conditions, including occasional El Nino and La Nina events, influence the distribution and numbers of marine mammals present in the Northeast Pacific Ocean, including Oregon, resulting in considerable year-to-year variation in the distribution and abundance of many marine mammal species (Forney and Barlow, 1998; Buchanan *et al.*, 2001; Escorza-Trevino, 2002; Ferrero *et al.*, 2002; Philbrick *et al.*, 2003). Thus, for some species the densities derived from recent surveys may not be representative of the densities that will be encountered during the proposed seismic survey. For this IHA application, cruise reports from the ORCAWALE 2008 surveys (NMFS, 2008) were inspected to assess whether there were any observable changes from the previous surveys of the same area.

Table 3 of SIO's application gives the average and maximum densities for each species of cetacean reported off Oregon and Washington, corrected for effort, based on the densities reported for the 1996, 2001, and 2005 surveys (Barlow and Forney, 2007). The densities from those studies had been corrected, by the original authors, for both detectability bias and availability bias. Detectability bias is associated with diminishing sightability with increasing lateral distance from the trackline. Availability bias refers to the fact that there is <100 percent probability of sighting an animals that is present along the survey trackline.

Table 3 of SIO's application also includes mean density information for three of the five pinnipeds species that occur off Oregon and Washington and mean and maximum densities for one of those species, from Bonnell *et al.* (1992). Densities were not calculated for the other two species because of the small number of sightings on systematic transect surveys. One of those, the northern elephant seal, was the dominant seal sighted during the ORCAWALE 2008 surveys (29 of 33 pinnipeds sighted off Oregon and Washington), so it was included at a density set at twice that of the northern fur seal, the other species sighted during the ORCAWALE 2008 surveys.

It should be noted that the following estimates of ''takes by harassment'' assume that the surveys will be undertaken and completed; in fact, the planned number of line kms has been increased by 25 percent to accommodate lines that may need to be repeated, equipment testing, etc. As is typical on offshore ship surveys, inclement weather, and equipment malfunctions are likely to cause delays and may limit the number of useful line kms of seismic operations that can be undertaken. Furthermore, any marine mammal sightings within or near the designated safety zones will result in the shut-down of seismic operations as a mitigation measure. Thus, the following estimates of the numbers of marine mammals potentially exposed to 160 dB are precautionary, and probably overestimate the actual numbers of marine mammals that might be involved. These estimates assume that there will be no weather, equipment, or mitigation delays, which is highly unlikely.

There is some uncertainty about the representativness of the data and the assumption used in the calculations. However, the approach used is believed to be the best available approach. Also, to provide some allowance for these uncertainties ''maximum estimates'' as well as ''best estimates'' of the numbers potentially affected have been derived. Best and maximum estimates are based on the average and maximum estimates of densities reported primarily by Barlow and Forney (2007) and Bonnell *et al.* (1992) described above. The estimated numbers of potential individuals exposed are presented below based on the 160 dB re 1 μPa (rms) Level B harassment criterion for all cetaceans and pinnipeds. It is assumed that a marine mammal exposed to airgun sounds this strong might change their behavior sufficiently to be considered ''taken by harassment.''

The number of different individuals that may be exposed to GI airgun sounds with received levels ≥160 dB re 1 μPa (rms) on one or more occasions was estimated by considering the total marine area that would be within the 160 dB radius around the operating airgun array on at least one occasion. The proposed seismic lines do not run parallel to each other in close proximity, which minimizes the number of times an individual mammal may be exposed during the survey. The best estimates in this section are based on the averages of the densities from the 1996, 2001, and 2005 NMFS surveys, and maximum estimates are based on the highest of the three densities. Table 4 of SIO's application and Table 2 of this **Federal Register** notice show the best and maximum estimates of the number of marine mammals that could potentially be affected during the seismic survey.

The number of different individuals potentially exposed to received levels ≥160 dB re 1 μPa (rms) was calculated by multiplying:

- The expected species density, either ''mean'' (i.e., best estimate) or ''maximum,'' times; and
- The area anticipated to be ensonified to that level during GI airgun operations.

The area expected to be ensonified was determined by entering the planned survey lines into a MapInfo Geographic Information System (GIS), using the GIS to identify the relevant areas by ''drawing'' the applicable 160 dB buffer around each seismic line (depending on water and tow depth) and then calculating the total area within the buffers. Areas where overlap occurred (because of intersecting lines) were included only once to determine the area expected to be ensonified. In the proposed survey, there is minimal overlap (5 percent for 160 dB), so virtually no marine mammal would be ensonified above those thresholds more than once.

Applying the approach described above, approximately 208 km2 (80.3 mi^2) would be within the 160 dB isopleth on one or more occasions during the surveys at all 16 OBS locations. For inshore OBS locations, approximately 60 km^2 (23 mi^2) would be within the 160 dB isopleths; that area was used for calculations for the pinniped species that could occur only at those locations. This approach does not allow for turnover in the mammal populations in the study area during the course of the surveys. That might underestimate actual numbers of individuals exposed, although the conservative distances used to calculate the area may offset this. In addition, the approach assumes that no cetaceans will move away or toward the trackline as the *Wecoma* approaches, in response to increasing sound levels prior to the time the levels reach 160 dB. Another way of interpreting the estimates that follow in Table 3 (below) is that they represent the number of individuals that are expected (in the absence of a seismic program) to occur in the waters that will be exposed to ≥160 dB re 1 μPa (rms).

TABLE 3. THE ESTIMATES OF THE POSSIBLE NUMBERS OF MARINE MAMMALS EXPOSED TO SOUND LEVELS GREATER THAN OR EQUAL TO 160 DB DURING SIO'S PROPOSED SEISMIC SURVEY OFF OREGON IN JULY 2009. THE PROPOSED SOUND SOURCE IS A SINGLE GI AIRGUN. RECEIVED LEVELS ARE EXPRESSED IN DB RE 1 μPA (RMS) (AVERAGED OVER PULSE DURATION), CONSISTENT WITH NMFS' PRACTICE. NOT ALL MARINE MAMMALS WILL CHANGE THEIR BEHAVIOR WHEN EXPOSED TO THESE SOUND LEVELS, BUT SOME MAY ALTER THEIR BEHAVIOR WHEN LEVELS ARE LOWER (SEE TEXT). SEE TABLES 2–4 IN SIO'S APPLICATION FOR FURTHER DETAIL.

Species	# of Individuals Exposed (best)[1]	# of Individuals Exposed (max)[1]	Approx. % Regional Population (best)[2]
Mysticetes			
Eastern Pacific gray whale *(Eschrichtius robustus)*	0	0	0
North Pacific right whale (*Eubalaena japonica*)	0	0	0
Humpback whale (Megaptera novaeangliae)	0	2	0
Minke whale(*Balaenoptera acutorostrata*)	0	0	0
Sei whale(*Balaenoptera borealis*)	0	0	0
Fin whale (*Balaenoptera physalus*)	0	1	0
Blue whale (*Balaenoptera musculus*)	0	1	0

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Species	# of Individuals Exposed (best)[1]	# of Individuals Exposed (max)[1]	Approx. % Regional Population (best)[2]
Odontocetes			
Sperm whale (*Physeter macrocephalus*)	0	8	0
Pygmy sperm whale (*Kogia breviceps*)	0	1	N.A.
Dwarf sperm whale (*Kogia sima*)	0	0	0
Cuvier's beaked whale (*Ziphius cavirostris*)	0	0	0
Baird's beaked whale (*Berardius bairdii*)	0	1	0
Blainville's beaked whale (Mesoplodon densirostris)	0	0	0
Hubb's beaked whale(*Mesoplodon carlhubbsi*)	0	0	0
Stejneger's beaked whale (*Mesoplodon stejnegeri*)	0	0	0
Mesoplodon sp. (unidentified)	0	1	0
Offshore bottlenose dolphin (*Tursiops truncatus*)	0	0	0
Striped dolphin (*Stenella coeruleoalba*)	0	0	0
Short-beaked common dolphin (*Delphinus delphis*)	4	9	<0.01
Pacific white-sided dolphin *Lagenorhynchus obliquidens*)	6	9	0.02
Northern right-whale dolphin (*Lissodelphis borealis*)	5	7	0.02
Risso's dolphin (*Grampus griseus*)	3	4	0.03
False killer whale (*Pseudorca crassidens*)	0	0	N.A.
Killer whale (*Orcinus orca*)	0	1	0
Short-finned pilot whale (*Globicephala macrorhynchus*)	0	0	0
Harbor porpoise (*Phocoena phocoena*)	0	0	0
Dall's porpoise (*Phocoenoides dalli*)	39	65	0.1
Pinnipeds			
Northern fur seal (*Callorhinus ursinus*)	3	26	<0.01

TABLE 3. THE ESTIMATES OF THE POSSIBLE NUMBERS OF MARINE MAMMALS EXPOSED TO SOUND LEVELS GREATER THAN OR EQUAL TO 160 DB DURING SIO'S PROPOSED SEISMIC SURVEY OFF OREGON IN JULY 2009. THE PROPOSED SOUND SOURCE IS A SINGLE GI AIRGUN. RECEIVED LEVELS ARE EXPRESSED IN DB RE 1 μPA (RMS) (AVERAGED OVER PULSE DURATION), CONSISTENT WITH NMFS' PRACTICE. NOT ALL MARINE MAMMALS WILL CHANGE THEIR BEHAVIOR WHEN EXPOSED TO THESE SOUND LEVELS, BUT SOME MAY ALTER THEIR BEHAVIOR WHEN LEVELS ARE LOWER (SEE TEXT). SEE TABLES 2–4 IN SIO'S APPLICATION FOR FURTHER DETAIL.—Continued

Species	# of Individuals Exposed (best)[1]	# of Individuals Exposed (max)[1]	Approx. % Regional Population (best)[2]
California sea lion (*Zalophus californianus*)	N.A.	N.A.	N.A.
Steller sea lion (*Eumetopias jubatus*)	1	N.A.	<0.01
Harbor seal (*Phoca vitulina richardsi*)	1	N.A.	<0.01
Northern elephant seal (*Mirounga angustirostris*)	5	52	<0.01

N.A.—Data not available or species status was not assessed
[1] Best estimate and maximum estimate density are from Table 3 of SIO's application.
[2] Regional population size estimates are from Table 2 (above).

Table 4 of SIO's application shows the best and maximum estimates of the number of exposures and the number of individual marine mammals that potentially could be exposed to greater than or equal to 160 dB re 1 μPa (rms) during the different legs of the seismic survey if no animals move away from the survey vessel.

The ''best estimate'' of the number of individual marine mammals that could be exposed to seismic sounds with received levels greater than or equal to 160 dB re 1 μPa (rms) (but below Level A harassment thresholds) during the survey is shown in Table 4 of SIO's application and Table 3 (shown above). The maximum estimates have been requested by SIO. The ''best estimate'' total includes 0 baleen whale individuals. These estimates were derived from the best density estimates calculated for these species in the area (see Table 4 of SIO's application). In addition, 0 sperm whales (0 percent of the regional population) as well as 0 beaked whales (0 percent of the regional population). Based on the best estimates, most (85.1 percent) of the marine mammals potentially exposed are dolphins and porpoises; short-beaked common, Pacific white-sided, Northern right-whale, Risso's dolphins and Dall's porpoises are estimated to be the most common species in the area, with best estimates of 4 (<0.01 percent of the regional population), 6 (0.02 percent), 5 (0.02 percent), 3 (0.03 percent), and 39 (0.01 percent) exposed to greater or equal to 160 dB re μPa (rms) respectively. The remainder of the marine mammals that may be potentially exposed are pinnipeds; Northern fur, harbor, and Northern elephant seals, and Steller sea lions are estimated to be the most common species in the area, with best estimates of 3 (<0.01 percent), 1 (<0.01 percent), 5 (<0.01 percent), and 1 (<0.01 percent) exposed to greater or equal to 160 dB re μPa (rms) respectively. Haul-outs of California sea lions and harbor seals are known to be located in the Newport, Oregon area. All of these numbers are considered small relative to the population sizes of the affected species or stocks.

Potential Effects on Marine Mammal Habitat

The proposed SIO seismic survey will not result in any permanent impact on habitats used by marine mammals, or to the food sources they use. The main impact issue associated with the proposed activity will be temporarily elevated noise levels and the associated direct effects on marine mammals, as described above. The following sections briefly review effects of airguns on fish and invertebrates, and more details are included in SIO's application and EA.

Potential Effects on Fish and Invertebrates

One reason for the adoption of airguns as the standard energy source for marine seismic surveys is that, unlike explosives, they have not been associated with large-scale fish kills. However, existing information on the impacts of seismic surveys on marine fish populations is very limited (see Appendix B of SIO's application). There are three types of potential effects on fish and invertebrates from exposure to seismic surveys: (1) pathological, (2) physiological, and (3) behavioral. Pathological effects involve lethal and temporary or permanent sub-lethal injury. Physiological effects involve temporary and permanent primary and secondary stress responses, such as changes in levels of enzymes and proteins. Behavioral effects refer to temporary and (if they occur) permanent changes in exhibited behavior (e.g., startle and avoidance behavior). The three categories are interrelated in complex ways. For example, it is possible that certain physiological and behavioral changes potentially could lead to an ultimate pathological effect on individuals (i.e., mortality).

The specific received sound levels at which permanent adverse effects to fish potentially could occur are little studied and largely unknown. Furthermore, the available information on the impacts of seismic surveys on marine fish is from studies of individuals or portions of a population; there have been no studies at the population scale. Thus, available information provides limited insight on possible real-world effects at the ocean or population scale. This makes drawing conclusions about impacts on fish problematic because ultimately, the most important aspect of potential impacts relates to how exposure to seismic survey sound affects marine fish populations and their viability, including their availability to fisheries.

The following sections provide a general synopsis of available information on the effects of exposure to seismic and other anthropogenic sound as relevant to fish. The information comprises results from scientific studies of varying degrees of rigor plus some anecdotal information. Some of the data sources may have serious shortcomings in methods, analysis, interpretation, and reproducibility that must be considered when interpreting their results (see Hastings and Popper, 2005). Potential adverse effects of the program's sound sources on marine fish are then noted.

Pathological Effects – The potential for pathological damage to hearing structures in fish depends on the energy level of the received sound and the physiology and hearing capability of the species in question (see Appendix B of SIO's application). For a given sound to result in hearing loss, the sound must exceed, by some specific amount, the hearing threshold of the fish for that sound (Popper, 2005). The consequences of temporary or permanent hearing loss in individual fish on a fish population is unknown; however, it likely depends on the number of individuals affected and whether critical behaviors involving sound (e.g., predator avoidance, prey capture, orientation and navigation, reproduction, etc.) are adversely affected.

Little is known about the mechanisms and characteristics of damage to fish that may be inflicted by exposure to seismic survey sounds. Few data have been presented in the peer-reviewed scientific literature. As far as we know, there are only two valid papers with proper experimental methods, controls, and careful pathological investigation implicating sounds produced by actual seismic survey airguns with adverse anatomical effects. One such study indicated anatomical damage and the second indicated TTS in fish hearing. The anatomical case is McCauley *et al.* (2003), who found that exposure to airgun sound caused observable anatomical damage to the auditory maculae of pink snapper (*Pagrus auratus*). This damage in the ears had not been repaired in fish sacrificed and examined almost two months after exposure. On the other hand, Popper *et al.* (2005) documented only TTS (as determined by auditory brainstem response) in two of three fish species from the Mackenzie River Delta. This study found that broad whitefish (*Coregonus nasus*) that received a sound exposure level of 177 dB re 1 $\mu Pa^2 \cdot s$ showed no hearing loss. During both studies, the repetitive exposure to sound was greater than would have occurred during a typical seismic survey. However, the substantial low-frequency energy produced by the airgun arrays [less than approximately 400 Hz in the study by McCauley *et al.* (2003) and less than approximately 200 Hz in Popper *et al.* (2005)] likely did not propagate to the fish because the water in the study areas was very shallow (approximately 9 m in the former case and less than 2 m in the latter). Water depth sets a lower limit on the lowest sound frequency that will propagate (the ''cutoff frequency'') at about one-quarter wavelength (Urick, 1983; Rogers and Cox, 1988).

Wardle *et al.* (2001) suggested that in water, acute injury and death of organisms exposed to seismic energy depends primarily on two features of the sound source: (1) the received peak pressure, and (2) the time required for the pressure to rise and decay. Generally, as received pressure increases, the period for the pressure to rise and decay decreases, and the chance of acute pathological effects increases. According to Buchanan *et al.* (2004), for the types of seismic airguns and arrays involved with the proposed program, the pathological (mortality) zone for fish and invertebrates would be expected to be within a few meters of the seismic source. Numerous other studies provide examples of no fish mortality upon exposure to seismic sources (Falk and Lawrence, 1973; Holliday *et al.*, 1987; La Bella *et al.*, 1996; Santulli *et al.*, 1999; McCauley *et al.*, 2000a,b, 2003; Bjarti, 2002; Hassel *et al.*, 2003; Popper *et al.*, 2005).

Some studies have reported, some equivocally, that mortality of fish, fish eggs, or larvae can occur close to seismic sources (Kostyuchenko, 1973; Dalen and Knutsen, 1986; Booman *et al.*, 1996; Dalen *et al.*, 1996). Some of the reports claimed seismic effects from treatments quite different from actual seismic survey sounds or even reasonable surrogates. Saetre and Ona (1996) applied a 'worst-case scenario' mathematical model to investigate the effects of seismic energy on fish eggs and larvae. They concluded that mortality rates caused by exposure to seismic surveys are so low, as compared to natural mortality rates, that the impact of seismic surveying on recruitment to a fish stock must be regarded as insignificant.

Physiological Effects – Physiological effects refer to cellular and/or biochemical responses of fish to acoustic stress. Such stress potentially could affect fish populations by increasing mortality or reducing reproductive success. Primary and secondary stress responses of fish after exposure to seismic survey sound appear to be temporary in all studies done to date (Sverdrup *et al.*, 1994; McCauley *et al.*, 2000a, 2000b). The periods necessary for the biochemical changes to return to normal are variable, and depend on numerous aspects of the biology of the species and of the sound stimulus (see Appendix B of SIO's application).

Summary of Physical (Pathological and Physiological) Effects – As indicated in the preceding general discussion, there is a relative lack of knowledge about the potential physical (pathological and physiological) effects of seismic energy on marine fish and invertebrates. Available data suggest that there may be physical impacts on egg, larval, juvenile, and adult stages at very close range. Considering typical source levels associated with commercial seismic arrays, close proximity to the source would result in exposure to very high energy levels. Whereas egg and larval stages are not able to escape such exposures, juveniles and adults most likely would avoid it. In the case of eggs and larvae, it is likely that the numbers adversely affected by such exposure would not be that different from those succumbing to natural mortality. Limited data regarding physiological impacts on fish and invertebrates indicate that these impacts are short term and are most apparent after exposure at close range.

The proposed seismic program for 2009 is predicted to have negligible to low physical effects on the various stags of fish and invertebrates for its relatively short duration (approximately 7 days) and unique survey lines extent. Therefore, physical effects of the proposed program on fish and invertebrates would not be significant.

Behavioral Effects – Behavioral effects include changes in the distribution, migration, mating, and catchability of fish populations. Studies investigating the possible effects of sound (including seismic survey sound) on fish behavior have been conducted on both uncaged and caged individuals (Chapman and Hawkins, 1969; Pearson *et al.*, 1992; Santulli *et al.*, 1999; Wardle *et al.*, 2001; Hassel *et al.*, 2003). Typically, in these studies fish exhibited a sharp ''startle'' response at the onset of a sound followed by habituation and a return to normal behavior after the sound ceased.

The existing body of information on the impacts of seismic survey sound on marine invertebrates is very limited. However, there is some unpublished and very limited evidence of the potential for adverse effects on invertebrates, thereby justifying further discussion and analysis of this issue. The three types of potential effects of exposure to seismic surveys on marine invertebrates are pathological, physiological, and behavioral. Based on the physical structure of their sensory organs, marine invertebrates appear to be specialized to respond to particle displacement components of an impinging sound field and not to the pressure component (Popper *et al*., 2001; see Appendix C of SIO's application).

The only information available on the impacts of seismic surveys on marine invertebrates involves studies of individuals; there have been no studies at the population scale. Thus, available information provides limited insight on possible real-world effects at the regional or ocean scale. The most important aspect of potential impacts concerns how exposure to seismic survey sound ultimately affects invertebrate populations and their viability, including availability to fisheries.

The following sections provide a synopsis of available information on the effects of exposure to seismic survey sound on species of decapod crustaceans and cephalopods, the two taxonomic groups of invertebrates on which most such studies have been conducted. The available information is from studies with variable degrees of scientific soundness and from anecdotal information. A more detailed review of the literature on the effects of seismic survey sound on invertebrates is provided in Appendix C of SIO's application.

Pathological Effects – In water, lethal and sub-lethal injury to organisms exposed to seismic survey sound could depend on at least two features of the sound source: (1) the received peak pressure, and (2) the time required for the pressure to rise and decay. Generally, as received pressure increases, the period for the pressure to rise and decay decreases, and the chance of acute pathological effects increases. For the single GI gun planned for the proposed program, the pathological (mortality) zone for crustaceans and cephalopods is expected to be within a few meters of the seismic source; however, very few specific data are available on levels of seismic signals that might damage these animals. This premise is based on the peak pressure and rise/decay time characteristics of seismic airgun arrays currently in use around the world.

Some studies have suggested that seismic survey sound has a limited pathological impact on early developmental stages of crustaceans (Pearson *et al*., 1994; Christian *et al*., 2003; DFO, 2004). However, the impacts appear to be either temporary or insignificant compared to what occurs under natural conditions. Controlled field experiments on adult crustaceans (Christian *et al*., 2003, 2004; DFO, 2004) and adult cephalopods (McCauley *et al*., 2000a,b) exposed to seismic survey sound have not resulted in any significant pathological impacts on the animals. It has been suggested that exposure to commercial seismic survey activities has injured giant squid (Guerra *et al*., 2004), but there is no evidence to support such claims.

Physiological Effects – Physiological effects refer mainly to biochemical responses by marine invertebrates to acoustic stress. Such stress potentially could affect invertebrate populations by increasing mortality or reducing reproductive success. Any primary and secondary stress responses (i.e., changes in haemolymph levels of enzymes, proteins, etc.) of crustaceans after exposure to seismic survey sounds appear to be temporary (hours to days) in studies done to date (J. Payne, DFO, pers. comm.). The periods necessary for these biochemical changes to return to normal are variable and depend on numerous aspects of the biology of the species and of the sound stimulus.

Behavioral Effects – There is increasing interest in assessing the possible direct and indirect effects of seismic and other sounds on invertebrate behavior, particularly in relation to the consequences for fisheries. Change in behavior could potentially affect such aspects as reproductive success, distribution, susceptibility to predation, and catchability by fisheries. Studies investigating the possible behavioral effect of exposure to seismic survey sound on crustaceans and cephalopods have been conducted on both uncaged and caged animals. In some cases, invertebrates exhibiting startle responses (e.g., squid in McCauley *et al*., 2000a,b). In other cases, no behavioral impacts were noted (e.g., crustaceans in Christian *et al*., 2003, 2004; DFO, 2004). There have been anecdotal reports of reduced catch rates of shrimp shortly after exposure to seismic surveys; however, other studies have not observed any significant changes in shrimp and catch rate (Andriguietto-Filho *et al*., 2005). Any adverse effects on crustacean and cephalopod behavior or fisheries attributable to seismic survey sound depend on the species in question and the nature of the fishery (season, duration, fishing method).

Because of the reasons noted above and the nature of the proposed activities, the proposed operations are not expected to cause significant impacts on habitats that could cause significant or long-term consequences for individual marine mammals or their populations or stocks. Similarly, any effects to food sources are expected to be negligible.

Subsistence Activities

There is no subsistence hunting for marine mammals in the waters off of the coast of Oregon that implicates MMPA Section 101(a)(5)(D).

Proposed Mitigation and Monitoring

Mitigation and monitoring measures proposed to be implemented for the proposed seismic survey have been developed and refined during previous SIO and NSF-funded seismic studies and associated environmental assessments (EAs), IHA applications, and IHAs. The mitigation and monitoring measures described herein represent a combination of procedures required by past IHAs for other similar projects and on recommended best practices in Richardson *et al.* (1995), Pierson *et al.* (1998), and Weir and Dolman (2007). The measures are described in detail below.

Mitigation measures that will be adopted during the proposed survey include:

(1) Speed or course alteration, provided that doing so will not compromise operational safety requirements;

(2) GI airgun shut-down procedures; and

(3) Special procedures for situations or species of particular concern, e.g., emergency shut-down procedures if a North Pacific right whale and minimization of approaches to slopes, if possible, to avoid beaked whale habitat.

Two other common mitigation measures, airgun array power-down and airgun array ramp-up, are not possible because only one, low-volume GI airgun will be used for the surveys. The thresholds for estimating Level A harassment take are also used in connection with proposed mitigation.

Vessel-based Visual Monitoring

Marine Mammal Visual Observers (MMVOs) will be based aboard the seismic source vessel and will watch for marine mammals near the vessel during daytime airgun operations and during start-ups of airguns at night. MMVOs will also watch for marine mammals near the seismic vessel for at least 30 minutes prior to the start of airgun operations and after an extended shut-down of the airguns. When feasible MMVOs will also make observations during daytime periods when the seismic system is not operating for comparison of sighting rates and animal behavior with vs. without airgun operations. Based on MMVO observations, the GI airgun will be shut-down (see below) when marine mammals are detected within or about to enter a designated EZ that corresponds to the 180 or 190 dB re 1 μPa (rms) isopleths, depending on whether the animal is a cetacean or pinniped . The MMVOs will continue to maintain watch to determine when the animal(s) are outside the EZ, and airgun operations will not resume until the animal has left that EZ. The predicted distances for the 180, and 190 dB EZs are listed according to the water depth in Table 1 above.

During seismic operations off of the coast of Oregon, at least two MMVOs will be based aboard the *Wecoma*. MMVOs will be appointed by SIO with NMFS concurrence. At least one MMVO will monitor the EZ for marine mammals during ongoing daytime GI airgun operations and nighttime startups of the airguns. MMVO(s) will be on duty in shifts no longer than 4 hours duration. The vessel crew will also be instructed to assist in detecting marine mammals and implementing mitigation measures (if practical). Before the start of the seismic survey the crew will be given additional instruction regarding how to do so.

The *Wecoma* is a suitable platform for marine mammal observations. Observing stations will be on the bridge wings, with observers' eyes approximately 6.5 m (21.3 ft) above the waterline and a 180 degree view outboard from either side, on the whaleback deck in front of the bridge, with observers eyes approximately 7 m (23 ft) above the waterline and approximately 200 degrees view forward, and on the aft control station, with observer's eyes approximately 5.5 m (18 ft) above the waterline and a approximately 180 degree view aft that includes the 40 m (131 ft) (180 dB) radius area around the GI airgun. The eyes of the bridge watch will be at a height of approximately 6.5 m; MMOs will repair to the enclosed bridge during any inclement weather.

During the daytime, the MMVO(s) will scan the area around the vessel systematically with reticle binoculars (e.g., 7x50), Big-eye binoculars (25x150), optical range finders, and with the naked eye. During darkness, night vision devices will be available, when required. The MMVOs will be in wireless communication with ship's officers on the bridge and scientists in the vessel's operations laboratory, so they can advise promptly of the need for avoidance maneuvers or GI airgun shut down.

Speed or Course Alteration – If a marine mammal is detected outside the EZ but is likely to enter based on its position and the relative movement of the vessel and animal, then if safety and scientific objectives allow, the vessel speed and/or course may be adjusted to minimize the likelihood of the animal entering the EZ. Typically, during seismic operations, major course and speed adjustments are often impractical when towing long seismic streamers and large source arrays, but are possible in this case because only one GI airgun and a short streamer will be used.

Shut-down Procedures – The operating airguns(s) will be shut-down if a marine mammal is detected within or approaching the EZ for the single GI airgun source. Following a shut-down, GI airgun activity will not resume until the marine mammal is outside the EZ for the full array. The animal will be considered to have cleared the EZ if it:

- Is visually observed to have left the EZ;
- Has not been seen within the EZ for 15 min in the case of species with shorter dive durations - small odontocetes and pinnipeds; and
- Has not been seen within the EZ for 30 min in the case of species with longer dive durations - mysticetes and large odontocetes, including sperm, pygmy sperm, dwarf sperm, killer, and beaked whales.

Procedures for Situations or Species of Particular Concern – Special mitigation procedures will be used for these species of particular concern as follows:

(1) The GI airgun will be shut-down if a North Pacific right whale is sighted at any distance from the vessel;

(2) To avoid beaked whale habitat, approach to slopes will be minimized, if possible, during the proposed survey. Avoidance of airgun operations over or near submarine canyons has become a standard mitigation measure, but there are none within or near the study area. Four of the 16 OBS locations are on the continental slope, but the GI airgun is low volume and it will operate only for a short time (approximately 2 hours at each location).

SIO and NSF will coordinate the planned marine mammal monitoring program associated with the seismic survey off the coast of Oregon with applicable U.S. agencies (e.g., NMFS), and will comply with their requirements.

Proposed Reporting

MMVO Data and Documentation

MMVOs will record data to estimate the numbers of marine mammals exposed to various received sound levels and to document apparent disturbance reactions or lack thereof. Data will be used to estimate numbers of animals potentially 'taken' by harassment (as defined in the MMPA). They will also provide information needed to order a shutdown of the seismic source when a marine mammal or sea turtles is within or near the EZ.

When a sighting is made, the following information about the sighting will be recorded:

(1) Species, group size, and age/size/sex categories (if determinable); behavior when first sighted and after initial sighting; heading (if consistent), bearing, and distance from seismic vessel; sighting cue; apparent reaction to the seismic source or vessel (e.g., none, avoidance, approach, paralleling, etc.); and behavioral pace.

(2) Time, location, heading, speed, activity of the vessel, sea state, visibility, cloud cover, and sun glare.

The data listed (time, location, etc.) will also be recorded at the start and end of each observation watch, and during a watch whenever there is a change in one or more of the variables.

All observations, as well as information regarding seismic source shut-down, will be recorded in a standardized format. Data accuracy will be verified by the MMVOs at sea, and preliminary reports will be prepared during the field program and summaries forwarded to the operating institution's shore facility and to NSF weekly or more frequently. MMVO observations will provide the following information:

(1) The basis for decisions about shutting down airgun arrays.

(2) Information needed to estimate the number of marine mammals potentially 'taken by harassment.' These data will be reported to NMFS.

(3) Data on the occurrence, distribution, and activities of marine mammals in the area where the seismic study is conducted.

(4) Data on the behavior and movement patterns of marine mammals seen at times with and without seismic activity.

A report will be submitted to NMFS within 90 days after the end of the cruise. The report will describe the operations that were conducted and sightings of marine mammals near the operations. The report will be submitted to NMFS, providing full documentation of methods, results, and interpretation pertaining to all monitoring. The 90–day report will summarize the dates and locations of seismic operations, and all marine mammal sightings (dates, times, locations, activities, associated seismic survey activities). The report will also include estimates of the amount and nature of potential ''take'' of marine mammals by harassment or in other ways.

All injured or dead marine mammals (regardless of cause) will be reported to NMFS as soon as practicable. The report should include species or description of animal, condition of animal, location, time first found, observed behaviors (if alive) and photo or video, if available.

Endangered Species Act (ESA)

Under Section 7 of the ESA, NSF has begun consultation with the NMFS, Office of Protected Resources, Endangered Species Division on this proposed seismic survey. NMFS will also consult on the issuance of an IHA under section 101(a)(5)(D) of the MMPA for this activity. Consultation will be concluded prior to a determination on the issuance of the IHA.

National Environmental Policy Act (NEPA)

NSF prepared a draft Environmental Assessment titled ''Marine Seismic Survey in the Northeast Pacific, July 2009.'' NSF's draft EA incorporates an ''Environmental Assessment (EA) of a Planned Low-Energy Marine Seismic Survey by the Scripps Institution of Oceanography in the Northeast Pacific Ocean, July 2009'' prepared by LGL Limited, Environmental Research Associates, on behalf of NSF and SIO. NMFS will either adopt NSF's EA or conduct a separate NEPA analysis, as necessary, prior to making a determination on the issuance of the IHA.

Preliminary Determinations

NMFS has preliminarily determined that the impact of conducting the low-energy marine seismic survey in the Northeast Pacific Ocean may result, at worst, in a temporary modification in behavior (Level B harassment) of small numbers of marine mammals. Further, this activity is expected to result in a negligible impact on the affected species or stocks. The provision requiring that the activity not have an unmitigable impact on the availability of the affected species or stock for subsistence uses is not implicated for this proposed action.

For reasons stated previously in this document, the negligible impact determination is supported by:

(1) The likelihood that, given sufficient ''notice'' through relatively slow ship speed, marine mammals are expected to move away from a noise source that is annoying prior to its becoming potentially injurious;

(2) The fact that cetaceans would have to be closer than 23 m (75 ft) in deep water, 35 m (115 ft) in intermediate depths, and 150 m (492 ft) in shallow water when the GI airgun is in use from the vessel to be exposed to levels of sound (180 dB) believed to have even a minimal chance of causing PTS;

(3) The fact that pinnipeds would have to closer than 8 m (26 ft) in deep water, 12 m (39 ft) in intermediate depths, and 95 m (312 ft) in shallow water when the GI airgun is in use from the vessel to be exposed to levels of sound (190 dB) believed to have even a minimal chance of causing PTS;

(4) The fact that marine mammals would have to be closer than 220 m (ft) in deep water, 330 m at intermediate depths, and 570 m (ft) in shallow water when the GI airgun is in use from the vessel to be exposed to levels of sound (160 dB) believed to have even a minimal chance at causing TTS; and

(5) The likelihood that marine mammal detection ability by trained observers is high at that short distance from the vessel, enabling the implementation of shut-downs to avoid injury, serious injury, or mortality. As a result, no take by injury or death is anticipated, and the potential for temporary or permanent hearing impairment is very low and will be avoided through the incorporation of the proposed mitigation measures.

While the number of marine mammals potentially incidentally harassed will depend on the distribution and abundance of marine mammals in the vicinity of the survey activity, the number of potential harassment takings is estimated to be small, less than one percent of any of the estimated population sizes, and has been mitigated to the lowest level practicable through incorporation of the measures mentioned previously in this document.

Proposed Authorization

As a result of these preliminary determinations, NMFS proposes to issue an IHA to SIO for conducting a low-energy marine seismic survey in the Northeast Pacific Ocean in July, 2009, provided the previously mentioned mitigation, monitoring, and reporting requirements are incorporated.

Dated: March 19, 2009.

James H. Lecky,

Director, Office of Protected Resources, National Marine Fisheries Service.

[FR Doc. E9–12149 Filed 5–22–09; 8:45 am]

BILLING CODE 3510–22–S

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XP28

Incidental Taking of Marine Mammals; Taking of Marine Mammals Incidental to the Explosive Removal of Offshore Structures in the Gulf of Mexico

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

ACTION: Notice; issuance of letters of authorization.

SUMMARY: In accordance with the Marine Mammal Protection Act (MMPA) and implementing regulations, notification is hereby given that NMFS has issued one-year Letters of Authorization (LOA) to take marine mammals incidental to the explosive removal of offshore oil and gas structures (EROS) in the Gulf of Mexico.

DATES: These authorizations are effective from June 1, 2009 through May 31, 2010.

ADDRESSES: The application and LOAs are available for review by writing to P. Michael Payne, Chief, Permits, Conservation, and Education Division, Office of Protected Resources, National Marine Fisheries Service, 1315 East-West Highway, Silver Spring, MD 20910–3235 or by telephoning the contact listed here (see **FOR FURTHER INFORMATION CONTACT**), or online at: *http://www.nmfs.noaa.gov/pr/permits/incidental.htm.* Documents cited in this notice may be viewed, by appointment, during regular business hours, at the aforementioned address.

FOR FURTHER INFORMATION CONTACT: Howard Goldstein or Ken Hollingshead, Office of Protected Resources, NMFS, 301–713–2289.

SUPPLEMENTARY INFORMATION: Section 101(a)(5)(A) of the MMPA (16 U.S.C. 1361 *et seq.*) directs the NMFS to allow, upon request, the incidental, but not intentional, taking of small numbers of marine mammals by United States citizens who engage in a specified activity (other than commercial fishing) within a specified geographical region, if certain findings are made by NMFS and regulations are issued. Under the MMPA, the term ''taking'' means to harass, hunt, capture, or kill or to attempt to harass, hunt capture, or kill marine mammals.

Authorization for incidental taking, in the form of annual LOAs, may be granted by NMFS for periods up to five years if NMFS finds, after notification and opportunity for public comment, that the taking will have a negligible impact on the species or stock(s) of marine mammals, and will not have an unmitigable adverse impact on the availability of the species or stock(s) for subsistence uses (where relevant). In addition, NMFS must prescribe regulations that include permissible methods of taking and other means effecting the least practicable adverse impact on the species and its habitat (i.e., mitigation), and on the availability of the species for subsistence uses, paying particular attention to rookeries, mating rounds, and areas of similar significance. The regulations also must include requirements pertaining to the monitoring and reporting of such taking. Regulations governing the taking incidental to EROS were published on June 19, 2008 (73 FR 34889), and remain in effect through July 19, 2013. For detailed information on this action, please refer to that *Federal Register* notice. The species that applicants may take in small numbers during EROS activities are bottlenose dolphins (*Tursiops truncatus*), Atlantic spotted dolphins (*Stenella frontalis*), pantropical spotted dolphins (*Stenella attenuata*), Clymene dolphins (*Stenella clymene*), striped dolphins (*Stenella coeruleoalba*), spinner dolphins (*Stenella longirostris*), rough-toothed dolphins (*Steno bredanensis*), Risso's dolphins (*Grampus griseus*), melon-headed whales (*Peponocephala electra*), short-finned pilot whales (*Globicephala macrorhynchus*), and sperm whales (*Physeter macrocephalus*).

Pursuant to these regulations, NMFS has issued an LOA to Ridgelake Energy, Inc., Fairways Offshore Exploration, Inc., El Paso Exploration & Production Company, L.P. Issuance of the LOAs is based on a finding made in the preamble to the final rule that the total taking by these activities (with monitoring, mitigation, and reporting measures) will result in no more than a negligible impact on the affected species or stock(s) of marine mammals and will not have an unmitigable adverse impact on subsistence uses. NMFS also finds that the applicant will meet the requirements contained in the implementing regulations and LOA, including monitoring, mitigation, and reporting requirements.

Dated: March 19, 2009.

James H. Lecky,

Director, Office of Protected Resources, National Marine Fisheries Service.

[FR Doc. E9–12153 Filed 5–22–09; 8:45 am]

BILLING CODE 3510–22–S

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN: 0648–XP32

South Atlantic Fishery Management Council; Public Meetings; Correction

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

ACTION: Notice of correction to a public meeting notice.

SUMMARY: Update to the South Atlantic Fishery Management Council's (Council) meeting of its Scientific and Statistical Committee (SSC). See **SUPPLEMENTARY INFORMATION** for additional details.

DATES: The meeting will be held June 7–12, 2009. See **SUPPLEMENTARY INFORMATION** for specific dates and times. (Note that these are the dates for the SAFMC meeting. The SSC meeting dates are listed below in the **SUPPLEMENTARY INFORMATION**.)

ADDRESSES: The Council meeting will be held at the Hutchinson Island Marriott, 555 NE Ocean Boulevard, Stuart, FL 34996; telephone: (800) 775–5936 or (772) 225–3700; fax: (772) 225–0003. Copies of documents are available from Kim Iverson, Public Information Officer, South Atlantic Fishery Management Council, 4055 Faber Place Drive, Suite 201, North Charleston, SC 29405.

FOR FURTHER INFORMATION CONTACT: Kim Iverson, Public Information Officer; telephone: (843) 571–4366 or toll free at (866) SAFMC–10; fax: (843) 769–4520; email: *kim.iverson@safmc.net*.

SUPPLEMENTARY INFORMATION: The original notice published in the **Federal Register** on May 18, 2008, 74 FR 23173. The following addition has been added to the agenda of the Scientific and Statistical Committee meeting. Except for the addition, all other previously-published information remains unchanged.

1. Scientific and Statistical Committee: June 7, 2009, 1:30 p.m. until 5 p.m.; June 8, 2009, 8:30 a.m. until 5 p.m.; and June 9, 2009, 8:30 a.m. until 5 p.m.

In addition to agenda items noted in a previous Notice, the SSC will also review an Independent Report on Red Snapper in the Southeast Data, Assessment, and Review (SEDAR) 15 stock assessment.

Documents regarding these issues are available from the Council office (see **ADDRESSES**).

Although non-emergency issues not contained in this agenda may come before this Council for discussion, those issues may not be the subjects of formal final Council 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 the public has been notified of the Council's intent to take final action to address the emergency.

Except for advertised (scheduled) public hearings and public comment, the times and sequence specified on this agenda are subject to change.

Special Accommodations

These meetings are physically accessible to people with disabilities. Requests for sign language interpretation or other auxiliary aids should be directed to the Council office (see **ADDRESSES**) by June 4, 2009.

Dated: May 19, 2009.

Tracey L. Thompson,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. E9–12035 Filed 5–22–09; 8:45 am]

BILLING CODE 3510–22–S

DEPARTMENT OF COMMERCE

Bureau of Industry and Security

Emerging Technology and Research Advisory Committee; Notice of Open Meeting

The Emerging Technology and Research Advisory Committee (ETRAC) will meet on June 11, 2009, 8:30 a.m., Room 3884, and on June 12, 2009, 8:30 a.m., Room 3884, at the Herbert C. Hoover Building, 14th Street between Pennsylvania and Constitution Avenues, NW., Washington, DC. The Committee advises the Office of the Assistant Secretary for Export Administration on emerging technology and research activities, including those related to deemed exports.

Thursday, June 11

Public Session

1. Welcome and Introduction.
2. Export Controls.
3. Deemed Exports Data Set.
4. Deemed Export Control Methodology Model Options.
5. Review Status.

Friday, June 12

Public Session

1. Deemed Export Control Methodology Model Options.

The meeting will be accessible via teleconference to 20 participants on a first come, first serve basis. To join the conference, submit inquiries to Ms. Yvette Springer at *Yspringer@bis.doc.gov*—no later than June 4, 2009.

A limited number of seats will be available for the meeting. Reservations are not accepted. To the extent that time permits, members of the public may present oral statements to the Committee. The public may submit written statements at any time before or after the meeting. However, to facilitate the distribution of public presentation materials to the Committee members, the Committee suggests that presenters forward the public presentation materials prior to the meeting to Ms. Springer via e-mail.

For more information, call Yvette Springer at (202) 482–2813.

Dated: May 20, 2009.

Teresa Telesco,

Assistant Committee Liaison Officer.

[FR Doc. E9–12172 Filed 5–22–09; 8:45 am]

BILLING CODE 3510–JT–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN: 0648–XP40

Pacific Fishery Management Council; Public Meetings

AGENCY: National Marine Fisheries Service, National Oceanic and Atmospheric Administration, Commerce.

ACTION: Notice of public meetings.

SUMMARY: The Pacific Fishery Management Council (Council) and its advisory entities will hold public meetings.

DATES: The Council and its advisory entities will meet June 11–18, 2009. The Council meeting will begin on Saturday, June 13, at 8 a.m., reconvening each day through Thursday, June 18, 2009. All meetings are open to the public, except a closed session will be held from 8 a.m. until 9 a.m. on Saturday, June 13 to address litigation and personnel matters. The Council will meet as late as necessary each day to complete its scheduled business.

ADDRESSES: The meetings will be held at Doubletree Hotel Spokane - City Center, 322 North Spokane Falls Court, Spokane, WA 99201; telephone: (509) 455–9600.

Council address: Pacific Fishery Management Council, 7700 NE Ambassador Place, Suite 101, Portland, OR 97220.

FOR FURTHER INFORMATION CONTACT: Dr. Donald O. McIsaac, Executive Director, telephone: (866) 806–7204 or (503) 820–2280; or access the Pacific Council website, *www.pcouncil.org* for the current meeting location, proposed agenda, and meeting briefing materials.

SUPPLEMENTARY INFORMATION: The following items are on the Pacific Council agenda, but not necessarily in this order:

A. Call to Order
1. Opening Remarks and Introductions
2. Roll Call
3. Report of the Executive Director
4. Approve Agenda
B. Open Comment Period
1. Comments on Non-Agenda Items
C. Habitat
1. Current Habitat Issues
D. Pacific Halibut Management
1. Proposed Procedures for Estimating Pacific Halibut Bycatch in the Groundfish Setline Fisheries
E. Groundfish Management
1. Groundfish Essential Fish Habitat Modifications
2. Proposed Process and Schedule for Developing Biennial (2011–12) Harvest Specifications and Management Measures
3. Fishery Management Plan Amendment 22-Open Access Fishery Limitation
4. Fishery management Plan Amendment 23-Implementing Annual Catch Limit Requirements
5. National Marine Fisheries Service Report
6. Part I of Stock Assessments for 2011–12 Groundfish Fisheries
7. Consideration of Inseason Adjustments
8. Preliminary Review of Exempted Fishing Permits for 2010
9. Final Consideration of Inseason Adjustments (if needed)
10. Fishery Management Plan (FMP) Amendments 20 and 21-Trawl Rationalization and Intersector Allocation - Regulatory Overview and Final Action on Miscellaneous Outstanding Issues and FMP Language
11. Fishery Management Plan Amendment 20-Trawl Rationalization - Final Action on Accumulation Limits and Divestiture
12. Fishery Management Plan Amendment 20-Trawl Rationalization - Final Action for Adaptive Management Program
F. Highly Migratory Species Management
1. Council Recommendations to International Regional Fishery Management Organizations
G. Administrative Matters
1. Membership Appointments and Council Operating Procedures
2. Fiscal Matters
3. Proposed Rule on Council Procedures
4. Approval of Council Meeting Minutes
5. Future Council Meeting Agenda and Workload Planning
H. Coastal Pelagic Species Management
1. Pacific Mackerel Management for 2009–10
2. Survey Methodology Review and Exempted Fishing Permit

Although non-emergency issues not contained in this agenda may come before the Pacific Council for discussion, those issues may not be the subject of formal Council 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 Fishery Conservation and Management Act, provided the public has been notified of the Council's intent to take final action to address the emergency.

The following is a schedule of ancillary and advisory body meetings:

SCHEDULE OF ANCILLARY MEETINGS

Thursday, June 11, 2009	.
Scientific and Statistical Committee Groundfish Subcommittee	8 am.
Friday, June 12, 2009	.
Groundfish Advisory Subpanel	8 am.
Groundfish Management Team	8 am.
Scientific and Statistical Committee	8 am.
Highly Migratory Species Management Team	1 pm.
Pacific Council Secretariat	1 pm.
Budget Committee	3 pm.
Saturday, June 13, 2009	.

SCHEDULE OF ANCILLARY MEETINGS—Continued

Pacific Council Secretariat	7 am.
California State Delegation	7 am.
Oregon State Delegation	7 am.
Washington State Delegation	7 am.
Groundfish Advisory Subpanel	8 am.
Groundfish Management Team	8 am.
Highly Migratory Advisory Subpanel	8 am.
Highly Migratory Management Team	8 am.
Scientific and Statistical Committee	8 am.
Enforcement Consultants	4:30 pm.
Sunday, June 14, 2009	.
Scientific and Statistical Committee	8 am.
Pacific Council Secretariat	9 am.
California State Delegation	9 am.
Oregon State Delegation	9 am.
Washington State Delegation	9 am.
Enforcement Consultants	10 am.
Groundfish Advisory Subpanel	10 am.
Groundfish Management Team	10 am.
Monday, June 15, 2009	.
Pacific Council Secretariat	7 am.
California State Delegation	7 am.
Oregon State Delegation	7 am.
Washington State Delegation	7 am.
Coastal Pelagic Species Advisory Subpanel	8 am.
Coastal Pelagic Species Management Team	8 am.
Enforcement Consultants	8 am.
Groundfish Advisory Subpanel	8 am.
Groundfish Management Team	8 am.
Tuesday, June 16, 2009	.
Pacific Council Secretariat	7 am.
California State Delegation	7 am.
Oregon State Delegation	7 am.
Washington State Delegation	7 am.
Enforcement Consultants	8 am.
Groundfish Advisory Subpanel	8 am.
Groundfish Management Team	8 am.
Wednesday, June 17, 2009	.
Pacific Council Secretariat	7 am.
California State Delegation	7 am.
Oregon State Delegation	7 am.
Washington State Delegation	7 am.
Enforcement Consultants	8 am.
Groundfish Advisory Subpanel	8 am.
Groundfish Management Team	8 am.
Thursday, June 18, 2009	.
Pacific Council Secretariat	7 am.
California State Delegation	7 am.
Oregon State Delegation	7 am.
Washington State Delegation	7 am.

Special Accommodations

These meetings are physically accessible to people with disabilities. Requests for sign language interpretation or other auxiliary aids should be directed to Ms. Carolyn Porter at (503) 820–2280 at least 5 days prior to the meeting date.

Dated: May 21, 2009.

Tracey L. Thompson,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. E9–12220 Filed 5–22–09; 8:45 am]

BILLING CODE 3510–22–S

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XP41

Caribbean Fishery Management Council; Public Meetings

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

ACTION: Notice of public meetings.

SUMMARY: The Caribbean Fishery Management Council (Council) and its Administrative Committee will hold meetings.

DATES: The meetings will be held on June 23–24, 2009. The Council will convene on Tuesday, June 23, 2009, from 9 a.m. to 5 p.m., and the Administrative Committee will meet from 5:15 p.m. to 6 p.m. They will reconvene on Wednesday, June 24, from 9 a.m. to 5 p.m.

ADDRESSES: The meetings will be held at the Carambola Beach Resort and Spa, located at Estate Davis Bay, St. Croix, U.S.V.I.

FOR FURTHER INFORMATION CONTACT: Caribbean Fishery Management Council, 268 Munoz Rivera Avenue, Suite 1108, San Juan, Puerto Rico 00918–1920, telephone: (787) 766–5926.

SUPPLEMENTARY INFORMATION: The Council will hold its 131st regular Council Meeting to discuss the items contained in the following agenda:

June 23, 2009 - 9 a.m. to 5 p.m.

•Call to Order
•Adoption of Agenda
•Consideration of the 130th Council Meeting Verbatim Transcription
•Executive Director's Report
•Bajo de Sico Public Hearings Report and Final Action
•ACLs/AMs Scoping Meetings Report

June 23, 2009 - 5:15 p.m. to 6 p.m.

•Administrative Committee Meeting
-AP/SSC/HAP Membership
-Budget
-FY 2009
- New Grants Rules
-Budget Petition: 5-years (2010–14)
-SOPPs Amendment(s)
-Other Business

June 24, 2009, 9 a.m. to 5 p.m.

•ACLs/AMs Scoping Meetings Report (Cont.)
•Queen Conch Fishery Issues
-Request for Emergency Action from DPNR
-Potential Interim Rule Request
•Administrative Committee Recommendations
•Other Business
-Enforcement and Meeting Attended by CFMC Members and Staff Reports
(These reports will be postponed for the next meeting in August, if there is no time on June 24, 2009.)
•Next Council Meeting

The established times for addressing items on the agenda may be adjusted as necessary to accommodate the timely completion of discussion relevant to the agenda items. To further accommodate discussion and completion of all items on the agenda, the meeting may be extended from, or completed prior to the date established in this notice.

The meetings are open to the public, and will be conducted in English. Fishers and other interested persons are invited to attend and participate with oral or written statements regarding agenda issues.

Although non-emergency issues not contained in this agenda may come before this group for discussion, those issues may not be subjects for formal action during this meeting. Actions will be restricted to those issues specifically identified in this notice, and any issues arising after publication of this notice that require emergency action under section 305(c) of the Magnuson-Stevens Fishery Conservation and Management Act, provided that the public has been notified of the Council's intent to take final action to address the emergency.

Special Accommodations

These meetings are physically accessible to people with disabilities. For more information or request for sign language interpretation and/other auxiliary aids, please contact Mr. Miguel A. Rolon, Executive Director, Caribbean Fishery Management Council, 268 Munoz Rivera Avenue, Suite 1108, San Juan, Puerto Rico 00918–1920; telephone: (787) 766–5926, at least 5 days prior to the meeting date.

Dated: May 19, 2009.

Tracey L. Thompson,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. E9–12044 Filed 5–22–09; 8:45 am]

BILLING CODE 3510–22–S

DEPARTMENT OF COMMERCE

Economic Development Administration

Notice of Petitions by Firms for Determination of Eligibility To Apply for Trade Adjustment Assistance

AGENCY: Economic Development Administration, Department of Commerce.

ACTION: Notice and opportunity for public comment.

Pursuant to Section 251 of the Trade Act of 1974 (19 U.S.C. 2341 *et seq.*), the Economic Development Administration (EDA) has received petitions for certification of eligibility to apply for Trade Adjustment Assistance from the firms listed below. EDA has initiated separate investigations to determine whether increased imports into the United States of articles like or directly competitive with those produced by each firm contributed importantly to the total or partial separation of the firm's workers, or threat thereof, and to a decrease in sales or production of each petitioning firm.

LIST OF PETITIONS RECEIVED BY EDA FOR CERTIFICATION OF ELIGIBILITY TO APPLY FOR TRADE ADJUSTMENT

[4/1/2009 through 5/8/2009]

Firm	Address	Date accepted for filing	Products
Control Technology Inc.	7608 North Hudson Ave., Oklahoma City, OK 73116.	4/8/2009	Static electric converters, power conditioners.
J&M Machining, Inc	313 North Ave., Skowhegan, ME 04976	4/13/2009	Precision machined components parts for industrial machinery.
Carving Craft, Inc	120 11th Street, Hickory, NC 28603	4/14/2009	Carvings, turnings, and moldings.
Pank Precision Products	11827 Janke Dr., Northbrook, IL 60062	4/14/2009	Precision metal components primarily for suspension systems.
American Window Enterprises.	200 Conant Street, Pawtucket, RI 02888	4/21/2009	Windows and doors are custom designed and manufactured from vinyl, wood, metal, and glass on-site.
TP Cycle & Engineering, Inc.	4 Finance Drive, Danbury, CT 06810	4/22/2009	Motorcycle engines and related parts.
Oklahoma Interpak Enterprise, Inc.	2424 North Main, Muskogee, OK 74402	4/1/2009	Corrugated board, chipboard, paperboard, to be used as containers, partitions, and pads.
Dufresne Manufacturing Co.	1380 East County Road, E. Vadnais, MN 55110	4/3/2009	Fabricated sheet metal components for medical devices.
Evo Inc	8140 SW Nimbus Avenue, Beaverton, OR 97008	4/7/2009	High end portable and non-portable electric and gas cooking appliances and grills.
Albany Chicago Company, LLC.	8200 100th St., Pleasant Prairie, WI 53158–2207	4/3/2009	A variety of large aluminum castings.
Electro Form Corporation.	128 Bevier, Street Binghamton, NY 13904	4/8/2009	Precision machined components primarily engaged in electromechanical assembly equipment.
Header Die & Tool, Inc	3022 Eastrock Ct., Box, Rockford, IL 61125	4/14/2009	Steel tooling used in the production of fasteners.

LIST OF PETITIONS RECEIVED BY EDA FOR CERTIFICATION OF ELIGIBILITY TO APPLY FOR TRADE ADJUSTMENT—Continued

[4/1/2009 through 5/8/2009]

Firm	Address	Date accepted for filing	Products
Tottser Tool and Die Shop, Inc.	1630 Republic Road, Huntington, PA 19006	5/8/2009	Metal stampings and die sets for the automotive industry.

Any party having a substantial interest in these proceedings may request a public hearing on the matter. A written request for a hearing must be submitted to the Office of Performance Evaluation, Room 7009, Economic Development Administration, U.S. Department of Commerce, Washington, DC 20230, no later than ten (10) calendar days following publication of this notice. Please follow the procedures set forth in Section 315.9 of EDA's final rule (71 FR 56704) for procedures for requesting a public hearing. The Catalog of Federal Domestic Assistance official program number and title of the program under which these petitions are submitted is 11.313, Trade Adjustment Assistance.

Dated: May 15, 2009.

William P. Kittredge,

Program Officer for TAA.

[FR Doc. E9–12115 Filed 5–22–09; 8:45 am]

BILLING CODE 3510–24–P

DEPARTMENT OF COMMERCE

International Trade Administration

A–421–811

Purified Carboxymethylcellulose from the Netherlands; Preliminary Results of Antidumping Duty Administrative Review

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

SUMMARY: In response to a request from petitioner Aqualon Company, a division of Hercules Incorporated (Aqualon), a U.S. manufacturer of purified carboxymethylcellulose (CMC), and respondent CP Kelco B.V. (CP Kelco), the Department of Commerce (the Department) is conducting an administrative review of the antidumping duty order on purified CMC from the Netherlands. This administrative review covers imports of subject merchandise produced and exported by CP Kelco (formerly known as Noviant B.V.).[1] The period of review (POR) is July 1, 2007, through June 30, 2008.

We preliminarily determine that sales of subject merchandise by CP Kelco have been made at less than normal value (NV). If these preliminary results are adopted in our final results, we will instruct U.S. Customs and Border Protection (CBP) to assess antidumping duties on appropriate entries based on the difference between the export price (EP) or constructed export price (CEP) and NV. Interested parties are invited to comment on these preliminary results.

EFFECTIVE DATE: May 26, 2009.

FOR FURTHER INFORMATION CONTACT: Patrick Edwards or Brian Davis, AD/CVD Operations, Office 7, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue, NW, Washington, DC 20230; telephone: (202) 482–8029 or (202) 482–7924, respectively.

SUPPLEMENTARY INFORMATION:

Background

On July 11, 2005, the Department published the antidumping duty order on purified CMC from the Netherlands. *See Notice of Antidumping Duty Orders: Purified Carboxymethylcellulose from Finland, Mexico, the Netherlands, and Sweden*, 70 FR 39734 (July 11, 2005) (CMC Order). On July 11, 2008, the Department published the opportunity to request an administrative review of, *inter alia*, purified CMC from the Netherlands for the period July 1, 2007, through June 30, 2008. *See Antidumping or Countervailing Duty Order, Finding, or Suspended Investigation; Opportunity To Request Administrative Review*, 73 FR 39948 (July 11, 2008).

In accordance with 19 CFR 351.213(b)(2), on July 11, 2008, CP Kelco and its U.S. affiliates (CP Kelco U.S., Inc. and JM Huber Corporation) timely requested that the Department initiate and conduct an administrative review of its sales of subject merchandise during the POR. Aqualon timely requested that the Department conduct an administrative review of sales of subject merchandise by Akzo Nobel Functional Chemicals B.V. (Akzo Nobel) and CP Kelco on July 14, 2008. On July 31, 2008, Akzo Nobel timely requested that the Department conduct an administrative review of its sales of merchandise covered by the order. On August 26, 2008, the Department published in the **Federal Register** a notice of initiation of this antidumping duty administrative review covering sales, entries and/or shipments of purified CMC for the period July 1, 2007, through June 30, 2008, from CP Kelco and Akzo Nobel. *See Initiation of Antidumping and Countervailing Duty Administrative Reviews*, 73 FR 50308 (August 26, 2008).

On September 5, 2008, and September 22, 2008, the Department issued its antidumping duty questionnaire to CP Kelco and Akzo Nobel, respectively. CP Kelco submitted its section A questionnaire response (AQR) on October 7, 2008. Akzo Nobel withdrew its request for review on October 9, 2008. Subsequently, petitioner withdrew its request for review of sales by Akzo Nobel on October 10, 2008. *See* 19 CFR 351.213(d)(1). CP Kelco submitted both its section B questionnaire response (BQR) and section C questionnaire response (CQR) on October 20, 2008, and its section D questionnaire response (DQR) on November 3, 2008.

On November 6, 2008, Aqualon provided deficiency comments for CP Kelco's BQR and CQR relating to, *inter alia*, data inconsistencies in both the home and U.S. markets.[2]

On November 12, 2008, the Department rescinded the administrative review with respect to Akzo Nobel. *See Purified Carboxymethylcellulose from the Netherlands: Partial Rescission of Antidumping Duty Administrative*

[1] In a prior review, the Department determined that CP Kelco was the successor-in-interest to Noviant B.V. *See Purified Carboxymethylcellulose from the Netherlands; Preliminary Results of Antidumping Duty Administrative Review*, 72 FR 44099, 44101 (August 7, 2007), unchanged in the final, *Purified Carboxymethylcellulose from the Netherlands: Final Results of Antidumping Duty Administrative Review*, 72 FR 70821, 70822 (December 13, 2007) (*Final Results of First Administrative Review*).

[2] The Department addressed Aqualon's comments in its December 16, 2008, issuance of its supplemental questionnaire.

Review, 73 FR 66841 (November 12, 2008).

On December 16, 2008, the Department issued its first sections A–C supplemental questionnaire to CP Kelco. On January 9, 2009, the Department issued its first section D supplemental questionnaire to CP Kelco. On January 22, 2009, CP Kelco submitted its sections A–C supplemental questionnaire response (SQR). On February 2, 2009, CP Kelco submitted its supplemental section D questionnaire response (SDQR). On February 4, 2009, the Department issued its second sections A–C supplemental questionnaire to CP Kelco. On February 9, 2009, Aqualon submitted comments on CP Kelco's February 2, 2009, SDQR. On February 11, 2009, CP Kelco submitted its second sections A–C supplemental questionnaire response (SSQR).

On March 27, 2009, the Department extended the deadline for the preliminary results by 46 days from April 2, 2009, until May 18, 2009. *See Purified Carboxymethylcellulose from the Netherlands; Extension of Time Limit for Preliminary Results of Antidumping Duty Administrative Review*, 74 FR 14959 (April 2, 2009).

Following the release of the Department's sales verification reports, the Department requested CP Kelco revise its home market and U.S. sales databases pursuant to the Department's verification findings and the minor corrections presented by company officials at the start of the verifications. *See* Letter to CP Kelco from Angelica L. Mendoza, Program Manager, regarding Submission of Revised Sales Databases, dated May 5, 2009. CP Kelco submitted its revised sales databases on May 11, 2009. On May 15, 2009, the Department issued an additional supplemental questionnaire to CP Kelco requesting further cost information for one particular control number, due May, 20, 2009 (*i.e.*, after the date of these preliminary results). Given that we will not receive this information until after the issuance of these preliminary results, we intend to address this issue in our final results. For further detail, *see* Memorandum to the File through Angelica L. Mendoza, Program Manager, Office 7, from Patrick Edwards, Senior Case Analyst, titled ''Analysis of Data Submitted by CP Kelco B.V. in the Preliminary Results of the Antidumping Duty Administrative Review of Purified Carboxymethylcellulose (CMC) from the Netherlands,'' dated May 18, 2009, (Preliminary Analysis Memorandum) at 9.

Period of Review

The POR is July 1, 2007, through June 30, 2008.

Scope of the Order

The merchandise covered by this order is all purified CMC, sometimes also referred to as purified sodium CMC, polyanionic cellulose, or cellulose gum, which is a white to off–white, non–toxic, odorless, biodegradable powder, comprising sodium CMC that has been refined and purified to a minimum assay of 90 percent. Purified CMC does not include unpurified or crude CMC, CMC Fluidized Polymer Suspensions, and CMC that is cross–linked through heat treatment. Purified CMC is CMC that has undergone one or more purification operations, which, at a minimum, reduce the remaining salt and other by–product portion of the product to less than ten percent. The merchandise subject to this order is currently classified in the Harmonized Tariff Schedule of the United States at subheading 3912.31.00. This tariff classification is provided for convenience and Customs purposes; however, the written description of the scope of this order is dispositive.

Verification

As provided in section 782(i) of the Tariff Act of 1930, as amended (the Act), and 19 CFR 351.307, we conducted a sales verification of the questionnaire responses of CP Kelco from February 23, 2009, through February 27, 2009, and CP Kelco's U.S. sales affiliate, CP Kelco U.S., Inc. (CP Kelco US) from March 2, 2009, through March 4, 2009. We used standard verification procedures, including on–site inspection of CP Kelco's production facility in Nijmegen, the Netherlands. Our verification results are outlined in the following memoranda: (1) Memorandum to the File, through Angelica L. Mendoza, Program Manager, ''Verification of the Home Market and Export Price Sales Responses of CP Kelco, B.V. in the Administrative Review of the Antidumping Duty Order on Purified Carboxymethylcellulose from the Netherlands,'' dated April 30, 2009 (Home Market Verification Report), and (2) Memorandum to the File, through Angelica L. Mendoza, Program Manager, ''Sales Verification of Sections A–C Questionnaire Responses Submitted by CP Kelco B.V. and CP Kelco U.S., Inc. in the Antidumping Duty Administrative Review of Purified Carboxymethylcellulose from the Netherlands: Verification of United States Affiliate CP Kelco U.S., Inc.,'' dated April 30, 2009 (CEP Verification Report). The Department conducted a verification of CP Kelco's cost responses in Nijmegen, the Netherlands, from March 16, 2009, through March 21, 2009. See Memorandum to the File from Christopher Zimpo, through Neal M. Halper, Director, and Peter Scholl, Lead Accountant, regarding ''Verification of the Cost Response of CP Kelco B.V. in the Antidumping Duty Administrative Review of Purified Carboxymethylcellulose from the Netherlands,'' dated May 18, 2009 (Cost Verification Report). Public versions of these reports are on file in the Central Records Unit (CRU) located in room 1117 of the main Department of Commerce Building, 14th Street and Constitution Avenue, NW, Washington, DC.

Date of Sale

CP Kelco reported the invoice date as the date of sale for its U.S. sales. The Department considers invoice date to be the presumptive date of sale (*see* 19 CFR 351.401(i)). For purposes of this review, we examined whether invoice date or another date better represents the date on which the material terms of sale were established. The Department, in reviewing CP Kelco's questionnaire responses, found that the material terms of sale are set on the date on which the invoice is issued. CP Kelco reported that, following the receipt of purchase orders, the terms of sale are susceptible and subject to changes in price and quantity until issuance of the sales invoice. *See* SQR at page 12; *see also* SQR at page 31; *see also* CEP Verification Report at page 14. Furthermore, in reviewing sales documentation during verification, we noted instances where the material terms of sale changed prior to the date of invoice (*see, e.g.*, CEP Verification Report at Exhibit 16). Therefore, we preliminarily determine that invoice date is the appropriate date of sale for CP Kelco's U.S. sales in this administrative review because it represents the date upon which the material terms of sale are established. This is consistent with the most recently completed administrative review of this order. *See Purified Carboxymethylcellulose from the Netherlands; Preliminary Results of Antidumping Duty Administrative Review*, 73 FR 45943, 45944 (August 8, 2008) (Preliminary Results of Second Administrative Review), unchanged at the final results, *Purified Carboxymethylcellulose from the Netherlands: Final Results of Antidumping Duty Administrative Review*, 73 FR 75393 (December 11,

2008) (*Final Results of Second Administrative Review*).

However, for instances where the date of shipment preceded the date of invoice, we have preliminarily determined to use the date of shipment for those sales. Normally, the Department employs invoice date as the date of sale in accordance with 19 CFR 351.401(i). However, it is the Department's practice to use shipment date as the date of sale when shipment date precedes invoice date. *See Certain Cold–Rolled and Corrosion–Resistant Carbon Steel Flat Products From Korea: Final Results of Antidumping Duty Administrative Reviews*, 63 FR 13170, 13172–73 (March 18, 1998); *see also Stainless Steel Sheet and Strip in Coils from the Republic of Korea: Preliminary Results and Partial Rescission of Antidumping Duty Administrative Review*, 71 FR 18074, 18079–80 (April 10, 2006), unchanged in *Stainless Steel Sheet and Strip in Coils from the Republic of Korea; Final Results and Rescission of Antidumping Duty Administrative Review in Part*, 72 FR 4486 (January 31, 2007), and the accompanying Issues and Decision Memorandum at Comments 4 and 5.

Similarly, based on our review of CP Kelco's questionnaire responses, we preliminarily find that the date of invoice constitutes the date on which the material terms of sale are established in the home market (*i.e.*, the Netherlands). *See* SQR at 12; *see also* Home Market Verification Report at pages 23–42; *see also* Home Market Verification Exhibit 21. CP Kelco reported that the terms of sale recorded on purchase orders in the home market are also subject to change, typically in the form of packing and product grade (which can affect price). *See* CP Kelco's AQR at 30–34. Therefore, we are using the invoice date as the date of sale for home market sales. For a further discussion of our date of sale analysis, *see* Preliminary Analysis Memorandum at 2.

Fair Value Comparisons

To determine whether sales of purified CMC from the Netherlands to the United States were made at less than fair value, we compared the EP or CEP to the NV, as described in the ''Export Price and Constructed Export Price'' and ''Normal Value'' sections of this notice below. In accordance with section 777A(d)(2) of the Act, we compared the EPs and CEPs of individual U.S. transactions to monthly weighted–average NVs.

Product Comparisons

In accordance with section 771(16) of the Act, we considered all purified CMC produced and sold by the respondent in the Netherlands during the POR that fit the description in the ''Scope of Order'' section of this notice to be foreign like products for purposes of determining appropriate product comparisons to U.S. sales. We compared U.S. sales with sales of the foreign like product in the home market. Where there were no sales of identical or similar merchandise made in the ordinary course of trade, we made product comparisons using constructed value (CV). Specifically, in making our comparisons, we used the following methodology. To determine the most similar model, we matched the foreign like product based on the physical characteristics reported by the respondent in the following order of importance: (1) grade, (2) viscosity, (3) degree of substitution, (4) particle size, and (5) solution characteristics. If an identical home–market model was reported, we made comparisons to weighted–average home market prices that were based on all sales which passed the cost of production (COP) test of the identical product during the relevant or contemporary month. *See* sections 771(16) and (35); *see also* 773(b)(1) of the Act. If there were no contemporaneous sales of an identical model, we identified the most similar home–market model. *See* section 773(b)(1) of the Act.

Export Price and Constructed Export Price

In accordance with section 772 of the Act, we calculate either an EP or a CEP, depending on the nature of each sale. Section 772(a) of the Act defines EP as the price at which the subject merchandise is first sold (or agreed to be sold) by the foreign exporter or producer before the date of importation to an unaffiliated purchaser in the United States, or to an unaffiliated purchaser for exportation to the United States. Section 772(b) of the Act defines CEP as the price at which the subject merchandise is first sold (or agreed to be sold) in the United States before or after the date of importation by or for the account of the producer or exporter of such merchandise or by a seller affiliated with the producer or exporter, to a purchaser not affiliated with the producer or exporter. CP Kelco classified two types of sales to the United States: (1) direct sales to end–users (*i.e.*, EP sales); and (2) sales via its U.S. affiliate, CP Kelco US, to end–users and distributors (*i.e.*, CEP sales). For purposes of these preliminary results, we have accepted CP Kelco's classifications.

We calculated EP based on prices charged to the first unaffiliated U.S. customer. We used the sale invoice date as the date of sale.[3] We based EP on the packed, delivered prices to unaffiliated purchasers in the United States. We made deductions for movement expenses in accordance with section 772(c)(2)(A) of the Act, which included foreign inland freight, international freight, marine insurance, U.S. brokerage and handling, U.S. inland freight offset by freight revenue (see below for further discussion), and U.S. customs duties. As noted below, we are relying upon adverse facts available with respect to the reported factoring transaction fees incurred by CP Kelco on its EP sales. Specifically, we are adjusting the EP using the highest reported factoring transaction fee. *See* ''Use of Adverse Facts Available'' section below; *see also* Preliminary Analysis Memorandum at 9, for further details.

We calculated CEP based on prices charged to the first unaffiliated U.S. customer after importation. We used the sale invoice date as the date of sale. We based CEP on the gross unit price from CP Kelco US to its unaffiliated U.S. customers, making adjustments where necessary for billing adjustments. Where applicable, and pursuant to sections 772(c)(2)(A) and (d)(1) of the Act, the Department made deductions for movement expenses (foreign inland freight, international freight, marine insurance, U.S. inland freight offset by freight revenue (*see* below for further discussion), U.S. warehousing, U.S. brokerage and handling, and U.S. customs duties).

In accordance with the recently completed administrative review of polyethylene retail carrier bags from the People's Republic of China, we capped the amount of freight revenue deducted at no greater than the amount of corresponding movement expenses for CP Kelco's sales of purified CMC to the United States and in the home market. *See Polyethylene Retail Carrier Bags from the People's Republic of China: Final Results of Antidumping Duty Administrative Review*, 74 FR 6857, 6858 (February 11, 2009) (*Bags from the PRC*), and the accompanying Issues and Decision Memorandum at Comment 4. As the Department explained in *Bags from the PRC*, section 772(c)(1) of the Act provides that the Department shall increase the price used to establish either export price or constructed export

[3] *See* Preliminary Analysis Memorandum at page 2 for a further discussion of this issue.

price in only the following three instances: (1) when not included in such price, the cost of all containers and coverings and all other costs, charges, and expenses incident to placing the subject merchandise in condition packed ready for shipment to the United States; (2) the amount of any import duties imposed by the country of exportation which have been rebated, or which have not been collected, by reason of the exportation of the subject merchandise to the United States; and (3) the amount of any countervailing duty imposed on the subject merchandise under subtitle A to offset an export subsidy. Section 773(a)(6) of the Act provides that the Department shall increase the price used to establish normal value by the cost of all containers and coverings and all other costs, charges, and expenses incident to placing the subject merchandise in condition packed ready for shipment to the United States.

In addition, 19 CFR 351.401(c) of the Department's regulations directs the Department to use a price in the calculation of U.S. price and normal value that is net of any price adjustments that are reasonably attributable to the subject merchandise or the foreign–like product (whichever is applicable). The term ''price adjustment'' is defined under 19 CFR 351.102(b)(38) as a ''change in the price charged for subject merchandise or the foreign like product, such as discounts, rebates, and post–sale adjustments, that are reflected in the purchaser's net outlay.''

In past cases, we have declined to treat freight–related revenues as additions to U.S. price under section 772(c) of the Act or price adjustments under 19 CFR 351.102(b). Rather, we have incorporated these revenues as offsets to movement expenses because they relate to the transportation of subject merchandise or the foreign–like product. *See, e.g., Stainless Steel Wire Rod from Sweden: Preliminary Results of Antidumping Duty Administrative Review*, 72 FR 51414, 51415 (September 7, 2007) (*SSWR Preliminary Results*) (unchanged in *Stainless Steel Wire Rod from Sweden: Final Results of Antidumping Duty Administrative Review*, 73 FR 12950 (March 11, 2008)).

Further, our offset practice limits the granting of an offset to situations where a respondent incurs expenses and realized revenue for the same type of activity. *See SSWR Preliminary Results*, 72 FR at 51415; *see also Bags from the PRC*, and accompanying Issues and Decision Memorandum at Comment 4; *see also Certain Orange Juice from Brazil: Final Results and Partial Rescission of Antidumping Duty Administrative Review*, 73 FR 46584 (August 11, 2008), and accompanying Issues and Decision Memorandum at Comment 7. According to CP Kelco's responses, freight revenues are revenues received from customers for invoice items covering transportation expenses, and arise when freight is not included in the selling price under the applicable terms of delivery, but when CP Kelco arranges and prepays freight for the customer. *See* CP Kelco's BQR at B–20 and CP Kelco's CQR at C–20 through C–21. Accordingly, CP Kelco incurred expenses and realized revenue for this activity. Therefore, we have limited the amount of the freight revenue used to offset CP Kelco's movement expenses to the amount of movement expenses incurred on the sale of subject merchandise or the foreign–like product. For further discussion of our treatment of freight revenue, *see* Preliminary Analysis Memorandum at 13 and 17.

In accordance with section 772(d)(1) of the Act, we also deducted, where applicable, U.S. direct selling expenses, including credit expenses, U.S. indirect selling expenses, and U.S. inventory carrying costs incurred in the United States and the Netherlands associated with economic activities in the United States. We also deducted CEP profit in accordance with section 772(d)(3) of the Act. As discussed below, we are relying upon adverse facts available with respect to the reported factoring transaction fees incurred by CP Kelco on its CEP sales. Specifically, we are adjusting the CEP using the highest reported factoring transaction fee. *See* ''Use of Adverse Facts Available'' section below; *see also* Preliminary Analysis Memorandum at 9, for further details.

Normal Value

A. Home Market Viability and Comparison Market Selection

In order to determine whether there is a sufficient volume of sales in the home market to serve as a viable basis for calculating NV (*e.g.*, whether the aggregate volume of home market sales of the foreign like product is equal to or greater than five percent of the aggregate volume of the subject merchandise sold in the United States), we compared respondent's volume of home market sales of the foreign like product to the volume of U.S. sales of the subject merchandise, in accordance with section 773(a)(1) of the Act. Pursuant to section 773(a)(1)(B)(ii)(II) of the Act, because CP Kelco's aggregate volume of home market sales of the foreign–like product was greater than five percent of its aggregate volume of U.S. sales of the subject merchandise, we determined that the home market was viable for comparison. Therefore, we have based NV on home market sales in the usual commercial quantities and in the ordinary course of trade.

B. Cost of Production (COP) Analysis

In accordance with section 773(b)(2)(A)(ii) of the Act, because we determined CP Kelco to have made sales below the cost of production in the most recently completed administrative review, the Department requested that CP Kelco respond to section D of the Department's antidumping duty questionnaire, as there were reasonable grounds to believe or suspect that CP Kelco made home market sales at prices below the cost of producing the merchandise in the current POR. *See Preliminary Results of Second Administrative Review*, 73 FR at 45946 (unchanged in *Final Results of Second Administrative Review).*

C. Calculation of Cost of Production

We have preliminarily relied on the COP information provided by CP Kelco. In accordance with section 773(b)(3) of the Act, we calculated the weighted–average COP for each model based on the sum of CP Kelco's material and fabrication costs for the foreign like product, plus amounts for selling, general, and administrative (SG&A) expenses, as well as packing costs.

D. Test of Home Market Prices

We compared CP Kelco's weighted–average COP figures to CP Kelco's home market sales prices (net of billing adjustments, any applicable movement expenses, direct and indirect selling expenses, and packing) of the foreign like product, as required under section 773(b) of the Act, to determine whether sales to the home market had been made at prices below COP. On a product–specific basis, we compared COP to home market prices, less any applicable movement charges.

In determining whether to disregard home market sales made at prices below the COP, we examined, in accordance with sections 773(b)(1)(A) and (B) of the Act, whether such sales were made in substantial quantities within an extended period of time, and whether such sales were made at prices which permitted the recovery of all costs within a reasonable period of time, in the normal course of trade.

E. Results of Cost Test

Pursuant to section 773(b)(2)(C) of the Act, where less than 20 percent of CP

Kelco's sales of a given model were at prices less than the COP, we did not disregard any below–cost sales of that model because these below–cost sales were not made in substantial quantities. Where 20 percent or more of CP Kelco's home market sales of a given model were at prices less than the COP, we disregarded the below–cost sales because such sales were made: (1) in substantial quantities within the POR (*i.e.*, within an extended period of time) in accordance with sections 773(b)(2)(B) and (C) of the Act, and (2) at prices which would not permit recovery of all costs within a reasonable period of time, in accordance with section 773(b)(2)(D) of the Act (*i.e.*, the sales were made at prices below the weighted–average per–unit COP for the POR). We used the remaining sales as the basis for determining NV, if such sales existed, in accordance with section 773(b)(1) of the Act. In this instant review, we found sales below the COP and have, as described above, disregarded such sales from our margin calculations. *See* Preliminary Analysis Memorandum at 8.

F. Price–to-Price Comparisons

We calculated NV based on prices to unaffiliated customers or prices to affiliated customers that we determined to be at arm's length. *See* 19 CFR 351.403(c). We used the sale invoice date as the date of sale. *See* 19 CFR 351.401(i). We increased or decreased price, as appropriate, for certain billing adjustments where applicable. We made deductions, where appropriate, for foreign inland freight incurred in the comparison market, pursuant to section 773(a)(6)(B) of the Act. Following the methodology described in the ''Export Price and Constructed Export Price'' section above, where applicable, we offset foreign inland freight expenses by freight revenue. In addition, when comparing sales of similar merchandise, we made adjustments for differences in cost attributable to differences in physical characteristics of the merchandise (*e.g.*, DIFMER) pursuant to section 773(a)(6)(C)(ii) of the Act and 19 CFR 351.411. We also made adjustments for differences in circumstances of sale (COS) in accordance with section 773(a)(6)(C)(iii) of the Act and 19 CFR 351.410. Specifically, we made COS adjustments for imputed credit expenses. We also made an adjustment, where appropriate, for the CEP offset in accordance with section 773(a)(7)(B) of the Act. *See* ''Level of Trade'' section below. Additionally, we deducted home market packing costs and added U.S. packing costs in accordance with sections 773(a)(6)(A) and (B) of the Act.

We have not made a deduction from NV for factoring transaction fees incurred by CP Kelco on certain home market sales, as noted in the ''Use of Adverse Facts Available'' section below.

G. Price–to-Constructed Value Comparisons

In accordance with section 773(a)(4) of the Act, we base NV on CV if we are unable to find a contemporaneous home market match of identical or similar merchandise for the U.S. sale. Section 773(e) of the Act provides that CV shall be based on the sum of the cost of materials and fabrication employed in making the subject merchandise, SG&A expenses, and profit. We calculated the cost of materials and fabrication for CP Kelco based on the methodology described in the COP section of this notice. In accordance with section 773(e)(2)(A) of the Act, we based SG&A expenses and profit on the amounts CP Kelco incurred and realized in connection with the production and sale of the foreign like product in the ordinary course of trade, for consumption in the foreign country (*i.e.*, the Netherlands). Accordingly, for sales of purified CMC for which we could not determine the NV based on comparison market sales, either because there were no useable sales of a comparable product or all sales of the comparable products failed the sales–below-cost test, we based NV on CV.

Use of Adverse Facts Available

For the reasons discussed below, we determine that the use of adverse facts available is appropriate for the preliminary results with respect to factoring transaction fees incurred by CP Kelco on certain home market and U.S. sales.

A. Use of Facts Available

Section 776(a)(2) of the Act provides that, if an interested party withholds information requested by the administering authority, fails to provide such information by the deadlines for submission of the information and in the form or manner requested, significantly impedes a proceeding under this title, or provides such information but the information cannot be verified as provided in section 782(i) of the Act, the administering authority shall use facts otherwise available in reaching the applicable determination.

In its SQR, CP Kelco explained that factoring is the process by which CP Kelco sells its accounts receivables to an affiliated finance company for payment of the receivables at a date earlier than CP Kelco would have received payment from the customer.[4] The factoring entity charges a transaction fee to CP Kelco, which is discounted from the face value of the actual receivable; per the Department's prior decisions in this case, CP Kelco reports these transaction fees as factoring expenses. *See* pages 30–31 of CP Kelco's SQR.

During our verification of the pre–selected and surprise home market and U.S. sales, we noted several discrepancies with regard to CP Kelco's reported transaction fees for factored sales. These transaction fees were reported on a percentage and per–unit basis. Specifically, the factoring transaction fee expressed as a percentage of gross unit price is reported in field FACTOR__PCTH, where the factoring transaction fee on a per–metric ton basis is reported in field FACTOR__DSTH. For the majority of the sales traces examined, we found systemic errors in CP Kelco's calculation and reporting of this expense.

Specifically, we discovered that CP Kelco miscalculated the reported and allegedly ''corrected'' (per the company's minor corrections presentation) factoring transaction fees in several instances where it used total invoice price, inclusive of value–added tax (VAT) and shipping costs, in its factoring calculations. In these instances, CP Kelco should have used the total invoice price less the VAT and shipping costs. Moreover, for the U.S. sales examined, we noted instances where factoring transaction fees were unreported, as well as instances in which factoring transaction fees were reported although the sales were not factored.[5] Therefore, considering all of the above, the Department is unable to rely upon CP Kelco's reporting of factoring transaction fees for certain home market and U.S. sales.

Because CP Kelco has failed to accurately report its factoring transaction fees to the best of its abilities, the Department must rely on facts available.

B. Application of Adverse Inference for Facts Available

Section 776(b) of the Act provides that, if the Department finds that an

[4] In past segments of this proceeding, the Department has included the transaction fees relating to the factoring of certain comparison market and U.S. sales by CP Kelco through an affiliated finance company in its dumping margin calculations. However, the Department intends to re-examine the appropriateness of including these affiliated transactions in its calculations in subsequent reviews of this proceeding.

[5] In some instances, the sale was initially factored but later reversed because the customer paid CP Kelco directly.

interested party has failed to cooperate by not acting to the best of its ability to comply with a request for information, the Department may use an inference adverse to the interests of that party in selecting the facts otherwise available. In addition, the *Statement of Administrative Action accompanying the Uruguay Round Agreements Act*, H.R. Rep. 103–316, Vol. 1, 103d Cong. (1994) (*SAA*), explains that the Department may employ an adverse inference ''to ensure that the party does not obtain a more favorable result by failing to cooperate than if it had cooperated fully.'' *See SAA* at 870. It is the Department's practice to consider, in employing adverse inferences, the extent to which a party may benefit from its own lack of cooperation. *See, e.g., Id.*

Furthermore, ''affirmative evidence of bad faith on the part of a respondent is not required before the Department may make an adverse inference.'' *See Antidumping Duties; Countervailing Duties, Final Rule*, 62 FR 27296, 27340 (May 19, 1997) (*Preamble*). We find that, by failing to accurately report the transaction fees associated with its factored sales in both the home and U.S. markets, CP Kelco failed to cooperate to the best of its abilities. CP Kelco failed to provide accurate, verifiable information with regard to this expense and, as such, we are unable to determine that CP Kelco's factoring transaction fees are either an accurate or a reasonable reflection of the company's own sales experience.[6] These errors were systemic for the vast majority of home market sales traces examined and, thus, call into question the accuracy of the universe of these reported factoring transaction fees in CP Kelco's sales databases. The Federal Circuit has stated that, ''§w§hile the adverse facts available standard does not require perfection and recognizes that mistakes sometimes occur, it does not condone inattentiveness, carelessness, or inadequate record keeping.'' *See Nippon Steel Corporation v. United States*, 337 F.3d 1373, 1382 (Fed. Cir. 2003). The AFA standard, moreover, assumes that because respondents are in control of their own information, they are required to take reasonable steps to present information that reflects its experience for reporting purposes before the Department. Therefore, we find it appropriate to use an inference that is adverse to the company's interests in selecting from among the facts otherwise available.

As adverse facts available, we have denied an adjustment to price for CP Kelco's factoring transaction fees incurred on all its home market sales for which factoring was reported. As stated above, with regard to CP Kelco's U.S. sales, we have selected the highest reported factoring transaction fee in the company's U.S. sales database and used that fee as the factoring transaction fee for all of CP Kelco's U.S. sales which were factored. While the discrepancies were less prevalent with respect to CP Kelco's factored U.S. sales, we have selected the highest reported factoring transaction fee in order to ensure that the company will not obtain a more favorable rate by failing to cooperate than had they cooperated fully. Moreover, because we are relying on the company's own information, there is no need to corroborate the chosen facts available under section 776(c) of the Act. For a detailed discussion on the Department's application of adverse facts available for factored home market sales in its margin calculations, *see* Preliminary Analysis Memorandum at 9.

Level of Trade

In accordance with section 773(a)(1)(B)(i) of the Act, to the extent practicable, we determine NV based on sales in the home market at the same level of trade (LOT) as the EP or CEP transaction. The LOT in the home market is the LOT of the starting–price sales in the home market or, when NV is based on CV, the LOT of the sales from which we derive SG&A expenses and profit. *See* 19 CFR 351.412(b)(2)(c). With respect to U.S. price for EP transactions, the LOT is also that of the starting–price sale, which is usually from the exporter to the importer. *Id.* For CEP, the LOT is that of the constructed sale from the exporter to the importer. *Id.*

To determine whether home market sales are at a different LOT from U.S. sales, we examine stages in the marketing process and selling functions along the chain of distribution between the producer and the unaffiliated customer. If the home market sales are at different LOTs, and the difference affects price comparability, as manifested in a pattern of consistent price differences between the sales on which NV is based and home market sales at the LOT of the export transaction, the Department makes an LOT adjustment in accordance with section 773(a)(7)(A) of the Act. For CEP sales, we examine stages in the marketing process and selling functions along the chain of distribution between the producer and the unaffiliated customer. We analyze whether different selling activities are performed, and whether any price differences (other than those for which other allowances are made under the Act) are shown to be wholly or partly due to a difference in LOT between the CEP and NV. *See* 773(a)(7)(A) of the Act.

Under section 773(a)(7)(A) of the Act, we make an upward or downward adjustment to NV for LOT if the difference in LOT involves the performance of different selling activities and is demonstrated to affect price comparability, based on a pattern of consistent price differences between sales at different LOTs in the country in which NV is determined. Finally, if the NV LOT is at a more advanced stage of distribution than the LOT of the CEP, but the data available do not provide an appropriate basis to determine a LOT adjustment, we reduce NV by the amount of indirect selling expenses incurred in the home market on sales of the foreign like product, but by no more than the amount of the indirect selling expenses incurred for CEP sales. *See* section 773(a)(7)(B) of the Act (the CEP offset provision).

In analyzing differences in selling functions, we determine whether the LOTs identified by the respondent are meaningful. *See Preamble*, 62 FR 27296, 27371. If the claimed LOTs are the same, we expect that the functions and activities of the seller should be similar. Conversely, if a party claims that LOTs are different for different groups of sales, the functions and activities of the seller should be dissimilar. *See Porcelain–on-Steel Cookware from Mexico: Final Results of Antidumping Duty Administrative Review*, 65 FR 30068 (May 10, 2000), and accompanying Issues and Decision Memorandum at Comment 6.

In the present review, CP Kelco did not claim a LOT adjustment. *See* CP Kelco's BQR at page B–18. In order to determine whether the home market sales were at different stages in the marketing process than the U.S. sales, we reviewed the distribution system in each market (*i.e.*, the ''chain of distribution''),[7] including selling

[6] CP Kelco, like all respondents, was provided ample opportunity to report correct and accurate information with regard to its factoring transaction fees in its AQR, BQR, CQR, two supplemental questionnaire responses (SQR and SSQR), as well as in its minor corrections presentation during the home market sales verification, which were also found to be incorrect. *See* Home Market Verification Report at Section X and VE-1.

[7] The marketing process in the United States and comparison market begins with the producer and extends to the sale to the final user or customer. The chain of distribution involved in the two markets may have many or few links, and the respondent's sales occur somewhere along this chain. In performing this evaluation, we considered

functions, class of customer (customer category), and the level of selling functions for each type of sale.

CP Kelco reported one LOT in the home market, the Netherlands, with two channels of distribution to two classes of customers: (1) direct sales from the plant to end users, and (2) direct sales from the plant to distributors. *See* Section CP Kelco's BQR at page B–11. Based on our review of evidence on the record, we find that home market sales to both customer categories and through both channels of distribution were substantially similar with respect to selling functions and stages of marketing. CP Kelco performed the same selling functions for sales in both home market channels of distribution, including sales negotiations, customer care, credit risk management, logistics, inventory maintenance, packing, freight and delivery services, collection, sales promotion, and guarantees, *etc. See* CP Kelco's AQR at pages A–14 through A–26. Each of these selling functions was identical in the intensity of their provision or only differed minimally, the exception being that CP Kelco provided direct sales personnel and technical support to a ''high'' degree of frequency to end–users, whereas these selling functions were provided with a ''moderate'' frequency to HM distributors. *See* CP Kelco's AQR at page A–26. However, after considering all of the above, we preliminarily find that CP Kelco had only one LOT for its home market sales.

CP Kelco reported one EP LOT and one CEP LOT, each with two separate channels of distribution in the United States. EP sales were made to end users and distributors either from inventory or made to order, and CEP sales were also made to end users and distributors and were either made from inventory or made to order. Upon examining CP Kelco's questionnaire responses, we preliminarily find that it has two channels of distribution. *See* CP Kelco's AQR at pages A–14 through A–15. *See also* CP Kelco's CQR at page C–11. Therefore, we preliminarily find that CP Kelco has two channels of distribution for EP sales, and two channels of distribution for CEP sales.

For CEP sales, we consider only the selling activities reflected in the price after the deduction of expenses and CEP profit under section 772(d) of the Act. *See Micron Tech. Inc. v. United States*, 243 F.3d 1301, 1314–15 (Fed. Cir. 2001). We reviewed the selling functions and services performed by CP Kelco on CEP sales as described in its questionnaire responses, after these deductions. We found that CP Kelco provides almost no selling functions to its U.S. affiliate in support of the CEP LOT. CP Kelco reported that the only services it provided for the CEP sales were logistics for freight, delivery and packing, and very limited customer care and inventory maintenance. *See* CP Kelco's AQR at page A–14 through A–26.

We then examined the selling functions performed by CP Kelco on its EP sales in comparison with the selling functions performed on CEP sales (after deductions). We found that CP Kelco performs an additional layer of selling functions at a greater frequency on its direct sales to unaffiliated U.S. customers which are not performed on its sales to its affiliate (*e.g.*, sales negotiations, credit risk management, collection, sales promotion, direct sales personnel, technical support, guarantees, and discounts). *See* CP Kelco's AQR at page A–26. Because these additional selling functions are significant, we find that CP Kelco's direct sales to unaffiliated U.S. customers (EP sales) are at a different LOT than its CEP sales.

Next, we compared the home market and EP sales. CP Kelco's home market and EP sales were both made to end users and distributors. In both cases, the selling functions performed by CP Kelco were almost identical for both markets. Particularly, in both markets, CP Kelco provided the following services: sales negotiations, credit risk management, customer care, logistics, inventory maintenance, packing, freight/delivery, collection, sales promotion, direct sales personnel, technical support, guarantees and discounts. *See* CP Kelco's SQR at page 26. Because the selling functions and channels of distribution are substantially similar, we preliminarily determine that the home market LOT is the same as the EP LOT. It was, therefore, unnecessary to make a LOT adjustment for comparison of CP Kelco's home market and EP prices.

According to section 773(a)(7)(B) of the Act, a CEP offset is appropriate when the LOT in the home market is at a more advanced stage than the LOT of the CEP sales and there is no basis for determining whether the difference in LOTs between NV and CEP affects price comparability. CP Kelco reported that it provided minimal selling functions and services for the CEP LOT and that, therefore, the home market LOT is more advanced than the CEP LOT. Based on our analysis of the channels of distribution and selling functions performed by CP Kelco for sales in the home market and CEP sales in the U.S. market (*i.e.*, sales support and activities provided by CP Kelco on sales to its U.S. affiliate), we preliminarily find that the home market LOT is at a more advanced stage when compared to CEP sales because CP Kelco provides many selling functions in the home market at a higher level of service (*i.e.*, sales negotiations, customer care, collection, direct sales personnel, technical support, etc.) as compared to selling functions performed for its CEP sales (*i.e.*, CP Kelco reported that the only services it provided for the CEP sales were logistics for freight, delivery and packing, and very limited inventory maintenance and customer care). *See* CP Kelco's AQR at page A–26. Thus, we find that CP Kelco's home market sales are at a more advanced LOT than its CEP sales. As there was only one LOT in the home market, there were no data available to determine the existence of a pattern of price differences, and we do not have any other information that provides an appropriate basis for determining a LOT adjustment; therefore, we applied a CEP offset to NV for CEP comparisons.

To calculate the CEP offset, we deducted the home market indirect selling expenses from NV for home market sales that were compared to U.S. CEP sales. As such, we limited the home market indirect selling expense deduction by the amount of the indirect selling expenses deducted in calculating the CEP as required under section 772(d)(1)(D) of the Act. *See* section 773(a)(7)(B) of the Act.

Currency Conversion

We made foreign currency conversions into U.S. dollars in accordance with section 773A(a) of the Act and 19 CFR 351.415 based on exchange rates in effect on the dates of the U.S. sales, as certified by the Federal Reserve Bank. *See* Import Administration website at: http://ia.ita.doc.gov/exchange/index.html.

Preliminary Results of Review

We preliminarily determine that for the period July 1, 2007, through June 30, 2008, the following dumping margin exists:

Manufacturer/Exporter	Weighted–Average Margin (percent)
CP Kelco B.V.	24.46

Disclosure and Public Comment

Pursuant to 19 CFR 351.224(b) of the Department's regulations, the Department will disclose to parties to the proceeding any calculations performed in connection with these preliminary results within five days

CP Kelco's narrative response to properly determine where in the chain of distribution the sale occurs.

after the date of publication of this notice. Pursuant to 19 CFR 351.309(c)(ii) of the Department's regulations, interested parties may submit written comments in response to these preliminary results. Unless extended by the Department, case briefs are to be submitted within 30 days after the date of publication of this notice, and rebuttal briefs, limited to arguments raised in case briefs, are to be submitted no later than five days after the time limit for filing case briefs. *See* 19 CFR 351.309(c)(1)(ii) and (d)(1). Parties who submit arguments in this proceeding are requested to submit with the argument: (1) a statement of the issues, (2) a brief summary of the argument, and (3) a table of authorities. *See* 19 CFR 351.309(c)(2). Case and rebuttal briefs must be served on interested parties in accordance with 19 CFR 351.303(f) of the Department's regulations. Executive summaries should be limited to five pages total, including footnotes. Further, we request that parties submitting briefs and rebuttal briefs provide the Department with a copy of the public version of such briefs on diskette.

Also, pursuant to 19 CFR 351.310(c) of the Department's regulations, within 30 days of the date of publication of this notice, interested parties may request a public hearing on arguments raised in the case and rebuttal briefs. Unless the Secretary specifies otherwise, the hearing, if requested, will be held two days after the date for submission of rebuttal briefs. *See* 19 CFR 351.310(d)(1). Parties will be notified of the time and location.

The Department will publish the final results of the administrative review, including the results of its analysis of issues raised in any case or rebuttal brief, no later than 120 days after publication of the preliminary results, unless extended. *See* section 751(a)(3)(A) of the Act; 19 CFR 351.213(h).

Assessment Rates

The Department shall determine, and CBP shall assess, antidumping duties on all appropriate entries in accordance with 19 CFR 351.212. The Department intends to issue assessment instructions for CP Kelco directly to CBP 15 days after the date of publication of the final results of this administrative review.

The Department clarified its ''automatic assessment'' regulation on May 6, 2003 (68 FR 23954). *See Antidumping and Countervailing Duty Proceedings: Assessment of Antidumping Duties*, 68 FR 23954 (May 6, 2003) (*Assessment Policy Notice*). This clarification will apply to entries of subject merchandise during the POR produced by companies included in the final results of this review for which the reviewed companies did not know their merchandise was destined for the United States. In such instances, we will instruct CBP to liquidate non–reviewed entries at the all–others rate if there is no rate for any intermediate company involved in the transaction. For a full discussion of this clarification, *see Assessment Policy Notice*.

Cash Deposit Requirements

The following cash deposit requirements will be effective upon publication of the final results of this administrative review for all shipments of the subject merchandise entered, or withdrawn from warehouse, for consumption on or after the publication date of the final results of this administrative review, as provided by section 751(a)(2)(c) of the Act: (1) the cash deposit rate for the reviewed company will be the rate established in the final results of review, except if the rate is less than 0.50 percent and, therefore, *de minimis* within the meaning of 19 CFR 351.106(c)(1); (2) for previously reviewed or investigated companies not listed above, the cash deposit rate will continue to be the company–specific rate published for the most recent period; (3) if the exporter is not a firm covered in this review or the original less–than–fair–value (LTFV) investigation, but the manufacturer is, the cash deposit rate will be the rate established for the most recent period for the manufacturer of the merchandise; and (4) the cash deposit rate for all other manufacturers or exporters will continue to be the all–others rate of 14.57 percent, which is the all–others rate established in the LTFV investigation. *See CMC Order*. These deposit requirements, when imposed, shall remain in effect until further notice.

Notification to Importers

This notice also serves as a preliminary reminder to importers of their responsibility under 19 CFR 351.402(f)(2) to file a certificate regarding the reimbursement of antidumping duties prior to liquidation of the relevant entries during this review period. Failure to comply with this requirement could result in the Secretary's presumption that reimbursement of antidumping duties occurred and the subsequent assessment of double antidumping duties.

This administrative review and notice are published in accordance with sections 751(a)(1) and 777(i)(1) of the Act.

Dated: May 18, 2009.

Ronald K. Lorentzen,

Acting Assistant Secretary for Import Administration.

[FR Doc. E9–12128 Filed 5–22–09; 8:45 am]

BILLING CODE 3510–DS–S

DEPARTMENT OF DEFENSE

Office of the Secretary

Strategic Environmental Research and Development Program, Scientific Advisory Board

AGENCY: Department of Defense.

ACTION: Notice.

SUMMARY: This Notice is published in accordance with Section 10(a)(2) of the Federal Advisory Committee Act (Pub. L. 92–463). The topic of the meeting on June 9–10, 2009 is to review new start and continuing research and development projects requesting Strategic Environmental Research and Development Program funds in excess of $1M. This meeting is open to the public. Any interested person may attend, appear before, or file statements with the Scientific Advisory Board at the time and in the manner permitted by the Board.

DATES: Tuesday, June 9, 2009 from 8 a.m. to 5:15 p.m. and Wednesday, June 10, 2009 from 8:30 a.m. to 12:30 p.m.

ADDRESSES: Allen/Mcghee/Page meeting room of the Washington Duke Inn, 3001 Cameron Blvd., Durham, NC 27705.

FOR FURTHER INFORMATION CONTACT: Mr. Jonathan Bunger, SERDP Office, 901 North Stuart Street, Suite 303, Arlington, VA or by telephone at (703) 696–2126.

Morgan E. Frazier,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. E9–12041 Filed 5–22–09; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Office of the Secretary

Veterans' Advisory Board on Dose Reconstruction; Meeting

AGENCY: Defense Threat Reduction Agency, DoD.

ACTION: Advisory Board Meeting Notice.

SUMMARY: Under the provisions of the Federal Advisory Committee Act of 1972 (5 U.S.C., Appendix, as amended) and the Sunshine in the Government Act of 1976 (5 U.S.C. 552b, as amended) the Defense Threat Reduction Agency

(DTRA) and the Department of Veterans Affairs (VA) announce the following advisory board meeting of the Veterans' Advisory Board on Dose Reconstruction (VBDR).

DATES: Wednesday, June 10, 2009, 8:30 a.m. to 12 p.m. and from 1:15 p.m. to 9 p.m.. The public is invited to attend. Public comment sessions are scheduled from 10:15 a.m. to 10:45 a.m. and from 6:30 p.m. to 7 p.m.

ADDRESSES: Hyatt Regency Bethesda Hotel, Old Georgetown Room, One Bethesda Metro Center (7400 Wisconsin Avenue), Bethesda, MD 20814.

FOR FURTHER INFORMATION CONTACT: The Veterans' Advisory Board on Dose Reconstruction Toll Free at 1–866–657–VBDR (8237). Additional information may be found at *http://vbdr.org.*

SUPPLEMENTARY INFORMATION:

Purpose of Meeting: To obtain, review and evaluate information related to the Board mission to provide guidance and oversight of the dose reconstruction and claims compensation programs for veterans of U.S.-sponsored atmospheric nuclear weapons tests from 1945–1962; veterans of the 1945–1946 occupation of Hiroshima and Nagasaki, Japan; and veterans who were prisoners of war in those regions at the conclusion of World War II. In addition, the advisory board will assist the VA and DTRA in communicating with the veterans.

Meeting Agenda: On Wednesday, the meeting will open with an introduction of the Board. The following briefings will be presented: ''Veterans Health Administration Procedures and the Ionizing Radiation Registry'' by Victoria Cassano, M.D.; ''Veterans Administration Regional Office, Jackson MS Presentation'' by Ms. Carol Sullivan; ''Update on the NTPR Dose Reconstruction Program'' by Dr. Paul Blake; ''Veterans Communication Effort'' by Mr. Ken Groves, and ''Update on the VA Radiation Claims Compensation Program for Veterans and VETNET'' by Mr. Thomas Pamperin. The morning session includes one half-hour open public comment session. In the afternoon, the four subcommittees established during the inaugural VBDR session will report on their activities since September 2008. The subcommittees are the ''Subcommittee on DTRA Dose Reconstruction Procedures,'' the ''Subcommittee on VA Claims Adjudication Procedures,'' the ''Subcommittee on Quality Management and VA Process Integration with DTRA Nuclear Test Personnel Review Program,'' and the ''Subcommittee on Communication and Outreach.'' The remainder of the meeting will be devoted to a discussion of the future of the VBDR with the exception of a one half-hour public comment period in the evening after dinner.

Meeting Accessibility: Pursuant to 5 U.S.C. 552b, as amended, and 41 CFR 102–3.140 through 102–3.165, and the availability of space, this meeting is open to the public. Seating is limited by the size of the meeting room. All persons must sign in legibly at the registration desk.

Written Statements: Pursuant to 41 CFR 102–3.105(j) and 102–3.140(c), interested persons may submit a written statement for consideration by the Veterans' Advisory Board on Dose Reconstruction. Written statements should be no longer than two type written pages and must address: the issue, discussion, and recommended course of action. Supporting documentation may also be included as needed to establish the appropriate historical context and to provide any necessary background information. Individuals submitting a written statement must submit their statement to the Board at 7910 Woodmont Ave., Suite 400, Bethesda, MD 20814–3095, at any point; however, if a written statement is not received at least 10 calendar days prior to the meeting, which is the subject of this notice, then it may not be provided to or considered by the Veterans' Advisory Board on Dose Reconstruction until its next open meeting.

The Chairperson will review all timely submissions with the Designated Federal Officer, and ensure they are provided to members of the Veterans' Advisory Board on Dose Reconstruction before the meeting that is the subject of this notice. After reviewing the written comments, the Chairperson and the Designated Federal Officer may choose to invite the submitter of the comments to orally present their issue during an open portion of this meeting or at a future meeting. However, due to the need to review the future of the Board and the options regarding these issues, oral presentations will not be presented at this meeting. If responses are needed, it will be done by correspondence to the participant.

The Chairperson, in consulting with the Designated Federal Officer, may, if desired, allot a specific amount of time for members of the public to present their issues for review and discussion by the Veterans' Advisory Board on Dose Reconstruction.

Public Comments: The June 10, 2009 meeting is open to the public. Approximately two one-half hour sessions will be reserved for public comments on issues related to the task of the Veterans' Advisory Board on Dose Reconstruction. Speaking time will be assigned on a first-come, first-served basis. The amount of time per speaker will be determined by the number of requests received, but is nominally five minutes each. All persons who wish to speak at the meeting must sign in legibly at the registration desk. Questions from the public will not be considered during this period. Speakers who wish to expand on their oral statements are invited to submit a written statement to the Veterans' Advisory Board on Dose Reconstruction at 7910 Woodmont Ave., Suite 400, Bethesda, MD 20814–3095.

Morgan E. Frazier,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. E9–12042 Filed 5–22–09; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Office of the Secretary

[Docket ID: DOD–2009–OS–0070]

Privacy Act of 1974; System of Records

AGENCY: Defense Logistics Agency, DoD.

ACTION: Notice to amend 2 systems of records.

SUMMARY: The Defense Logistics Agency is proposing to amend system of records notices in its existing inventory of record systems subject to the Privacy Act of 1974 (5 U.S.C. 552a), as amended.

DATES: The proposed action will be effective without further notice on June 25, 2009 unless comments are received which would result in a contrary determination.

ADDRESSES: Chief Privacy and FOIA Officer, Headquarters Defense Logistics Agency, ATTN: DGA, 8725 John J. Kingman Road, Suite 1644, Fort Belvoir, VA 22060–6221.

FOR FURTHER INFORMATION CONTACT: Mr. Lewis Oleinick at (703) 767–6194.

SUPPLEMENTARY INFORMATION: The Defense Logistics Agency's system of record notices subject to the Privacy Act of 1974 (5 U.S.C. 552a), as amended, have been published in the **Federal Register** and are available from the address above.

The specific changes to the record system being amended are set forth below followed by the notice, as amended, published in its entirety. The proposed amendment is not within the purview of subsection (r) of the Privacy Act of 1974 (5 U.S.C. 552a), as amended, which requires the submission of new or altered systems reports.

Dated: May 18, 2009.

Morgan E. Frazier,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

S180.20

SYSTEM NAME:

Biography File (July 19, 2006, 71 FR 41007).

CHANGES:

System identifier:

Delete entry and replace with ''S190.24.''

* * * * *

STORAGE:

Delete entry and replace with ''Records are maintained on electronic storage media.''

* * * * *

SAFEGUARDS:

Delete entry and replace with ''No specific safeguards required. Biographies are submitted by the subject individual with the understanding that they will be posted to a public facing DLA Web page.''

SYSTEM MANAGER(S) AND ADDRESS:

Delete entry and replace with ''Director, DLA Public Affairs Office, Headquarters, Defense Logistics Agency, 8725 John J. Kingman Road, Stop 2533, Fort Belvoir, VA 22060–6221, and the Heads of the Public Affairs Offices within each DLA field activity. Official mailing addresses are published as an appendix to DLA's compilation of systems of records notices.''

NOTIFICATION PROCEDURE:

Delete entry and replace with ''Individuals seeking to determine whether information about themselves is contained in this system of records should address written inquiries to the Privacy Act Office, Headquarters, Defense Logistics Agency, ATTN: DGA, 8725 John J. Kingman Road, Suite 1644, Fort Belvoir, VA 22060–6221 or to the Privacy Act Office of the DLA field activity where assigned. Official mailing addresses are published as an appendix to DLA's compilation of systems of records notices.

Inquiry must contain the subject individual's full name, current address, and telephone number.''

RECORD ACCESS PROCEDURES:

Delete entry and replace with ''Individuals seeking access to information about themselves contained in this system of records should address written inquiries to the Privacy Act Office, Headquarters, Defense Logistics Agency, ATTN: DGA, 8725 John J. Kingman Road, Suite 1644, Fort Belvoir, VA 22060–6221 or to the Privacy Act Office of the DLA field activity where assigned. Official mailing addresses are published as an appendix to DLA's compilation of systems of records notices.

Inquiry must contain the subject individual's full name, current address, and telephone number.''

CONTESTING RECORD PROCEDURES:

Delete entry and replace with ''The DLA rules for accessing records, for contesting contents, and appealing initial agency determinations are contained in 32 CFR part 323, or may be obtained from the Privacy Act Office, Headquarters, Defense Logistics Agency, ATTN: DGA, 8725 John J. Kingman Road, Suite 1644, Fort Belvoir, VA 22060–6221.''

* * * * *

S190.24

SYSTEM NAME:

Biography File.

SYSTEM LOCATION:

Headquarters, Defense Logistics Agency, Public Affairs Office, 8725 John J. Kingman Road, Stop 2533, Fort Belvoir, VA 22060–6221, and the Public Affairs Offices of the DLA Field Activities. Official mailing addresses are published as an appendix to DLA's compilation of systems of records notices.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

Selected civilian and military personnel currently and formerly assigned to DLA and other persons affiliated with DLA and the Department of Defense (DoD).

CATEGORIES OF RECORDS IN THE SYSTEM:

Biographical information provided by the individual.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

5 U.S.C. 301, Departmental Regulations and 10 U.S.C. 133, Under Secretary of Defense for Acquisition, Technology, and Logistics.

PURPOSE(S):

Information is maintained as background material for news and feature articles covering activities, assignments, retirements, and reassignments of key individuals; for use in introductions; in the preparation of speeches for delivery at change of command, retirement, award ceremonies, and community relations events; for congressional functions; and for site visits.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND THE PURPOSES OF SUCH USES:

In addition to those disclosures generally permitted under 5 U.S.C. 552a(b) of the Privacy Act of 1974, these records contained therein may specifically be disclosed outside the DoD as a routine use pursuant to 5 U.S.C. 552a(b)(3) as follows:

To Federal, state, and local agency officials and/or private sector entities for use as background information for introductions, briefings, Congressional testimony, and/or meetings.

The DoD ''Blanket Routine Uses'' apply to this system of records.

POLICIES AND PRACTICES FOR STORING, RETRIEVING, ACCESSING, RETAINING, AND DISPOSING OF RECORDS IN THE SYSTEM:

STORAGE:

Records are maintained on electronic storage media.

RETRIEVABILITY:

Records are retrieved alphabetically by last name of individual.

SAFEGUARDS:

No specific safeguards required. Biographies are submitted by the subject individual with the understanding that they will be posted to a public facing DLA Web page.

RETENTION AND DISPOSAL:

Files are destroyed 2 years after retirement, transfer, separation, or death of the person concerned.

SYSTEM MANAGER(S) AND ADDRESS:

Director, DLA Public Affairs Office, Headquarters, Defense Logistics Agency, 8725 John J. Kingman Road, Stop 2533, Fort Belvoir, VA 22060–6221, and the Heads of the Public Affairs Offices within each DLA field activity. Official mailing addresses are published as an appendix to DLA's compilation of systems of records notices.

NOTIFICATION PROCEDURE:

Individuals seeking to determine whether information about themselves is contained in this system of records should address written inquiries to the Privacy Act Office, Headquarters, Defense Logistics Agency, ATTN: DGA, 8725 John J. Kingman Road, Suite 1644, Fort Belvoir, VA 22060–6221 or to the Privacy Act Office of the DLA field activity where assigned. Official mailing addresses are published as an appendix to DLA's compilation of systems of records notices.

Inquiry must contain the subject individual's full name, current address, and telephone number.

RECORD ACCESS PROCEDURES:

Individuals seeking access to information about themselves contained in this system of records should address written inquiries to the Privacy Act Office, Headquarters, Defense Logistics Agency, ATTN: DGA, 8725 John J. Kingman Road, Suite 1644, Fort Belvoir, VA 22060–6221 or to the Privacy Act Office of the DLA field activity where assigned. Official mailing addresses are published as an appendix to DLA's compilation of systems of records notices.

Inquiry must contain the subject individual's full name, current address, and telephone number.

CONTESTING RECORD PROCEDURES:

The DLA rules for accessing records, for contesting contents, and appealing initial agency determinations are contained in 32 CFR part 323, or may be obtained from the Privacy Act Office, Headquarters, Defense Logistics Agency, ATTN: DGA, 8725 John J. Kingman Road, Suite 1644, Fort Belvoir, VA 22060–6221.

RECORD SOURCE CATEGORIES:

The individual's record subject and record subject's employing agency or organization.

EXEMPTIONS CLAIMED FOR THE SYSTEM:

None.

S180.25

SYSTEM NAME:

Public Affairs Subscription Mailing Lists (August 25, 2006, 71 FR 50398).

CHANGES:

SYSTEM IDENTIFIER:

Delete entry and replace with ''S190.32.''

* * * * *

SYSTEM LOCATION:

Delete entry and replace with ''Headquarters, Defense Logistics Agency, Public Affairs Office, 8725 John J. Kingman Road, Stop 2533, Fort Belvoir, VA 22060–6221, and the Public Affairs Offices of the DLA field activities. Official mailing addresses are published as an appendix to DLA's compilation of systems of records notices.''

* * * * *

STORAGE:

Delete entry and replace with ''Records are maintained on electronic storage media.''

* * * * *

SAFEGUARDS:

Delete entry and replace with ''Access is limited to those individuals who require the records for the performance of their official duties. Electronic records are maintained in buildings with controlled or monitored access. During non-duty hours, records are secured in locked or guarded buildings, locked offices, or guarded cabinets. The electronic records systems employ user identification and password or smart card technology protocols.''

SYSTEM MANAGER(S) AND ADDRESS:

Delete entry and replace with ''Director, DLA Public Affairs Office, Headquarters, Defense Logistics Agency, 8725 John J. Kingman Road, Stop 2533, Fort Belvoir, VA 22060–6221, and the Heads of the Public Affairs Offices within each DLA field activity. Official mailing addresses are published as an appendix to DLA's compilation of systems of records notices.''

NOTIFICATION PROCEDURE:

Delete entry and replace with ''Individuals seeking to determine whether this system of records contains information about themselves should address written inquiries to the Privacy Act Office, Headquarters, Defense Logistics Agency, ATTN: DGA, 8725 John J. Kingman Road, Suite 1644, Fort Belvoir, VA 22060–6221 or to the Privacy Act Office of the particular DLA field activity involved. Official mailing addresses are published as an appendix to DLA's compilation of systems of records notices.

Inquiry must contain the subject individual's full name and current mailing address to permit locating the record.''

RECORD ACCESS PROCEDURE:

Delete entry and replace with ''Individuals seeking access to information about themselves contained in this system of records should address written inquiries to the Privacy Act Office, Headquarters, Defense Logistics Agency, ATTN: DGA, 8725 John J. Kingman Road, Suite 1644, Fort Belvoir, VA 22060–6221 or to the Privacy Act Office of the particular DLA field activity involved. Official mailing addresses are published as an appendix to DLA's compilation of systems of records notices.

Inquiry must contain the subject individual's full name and current mailing address to permit locating the record.''

CONTESTING RECORD PROCEDURES:

Delete entry and replace with ''The DLA rules for accessing records, for contesting contents and appealing initial agency determinations are contained in 32 CFR part 323, or may be obtained from the Privacy Act Office, Headquarters, Defense Logistics Agency, ATTN: DGA, 8725 John J. Kingman Road, Suite 1644, Fort Belvoir, VA 22060–6221.''

* * * * *

S190.32

SYSTEM NAME:

Public Affairs Subscription Mailing Lists.

SYSTEM LOCATION:

Headquarters, Defense Logistics Agency, Public Affairs Office, 8725 John J. Kingman Road, Stop 2533, Fort Belvoir, VA 22060–6221, and the Public Affairs Offices of the DLA field activities. Official mailing addresses are published as an appendix to DLA's compilation of systems of records notices.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

Individuals and organizations who have registered with DLA Public Affairs Offices to automatically receive magazines, newsletters, periodicals and other professional publications.

CATEGORIES OF RECORDS IN THE SYSTEM:

Records maintained include individual's name, home or business telephone number, e-mail and mailing addresses, customer number, and publication(s) of interest.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

5 U.S.C. 301, Departmental Regulations, and 10 U.S.C. 133, Under Secretary of Defense for Acquisition, Technology, and Logistics.

PURPOSE(S):

The system is used to produce subscription mailing lists for distribution of DLA publications, and to perform statistical analyses of reader interest and opinion.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND THE PURPOSES OF SUCH USES:

In addition to those disclosures generally permitted under 5 U.S.C. 552a(b) of the Privacy Act of 1974, these records contained therein may specifically be disclosed outside the DOD as a routine use pursuant to 5 U.S.C. 552a(b)(3) as follows:

The DoD ''Blanket Routine Uses'' apply to this system of records.

POLICIES AND PRACTICES FOR STORING, RETRIEVING, ACCESSING, RETAINING, AND DISPOSING OF RECORDS IN THE SYSTEM:

STORAGE:

Records are maintained on electronic storage media.

RETRIEVABILITY:

Records are retrieved by individual's name and address.

SAFEGUARDS:

Access is limited to those individuals who require the records for the performance of their official duties. Electronic records are maintained in buildings with controlled or monitored access. During non-duty hours, records are secured in locked or guarded buildings, locked offices, or guarded cabinets. The electronic records systems employ user identification and password or smart card technology protocols.

RETENTION AND DISPOSAL:

Records are destroyed when superseded or obsolete.

SYSTEM MANAGER(S) AND ADDRESS:

Director, DLA Public Affairs Office, Headquarters, Defense Logistics Agency, 8725 John J. Kingman Road, Stop 2533, Fort Belvoir, VA 22060–6221, and the Heads of the Public Affairs Offices within each DLA field activity. Official mailing addresses are published as an appendix to DLA's compilation of systems of records notices.

NOTIFICATION PROCEDURE:

Individuals seeking to determine whether this system of records contains information about themselves should address written inquiries to the Privacy Act Office, Headquarters, Defense Logistics Agency, ATTN: DGA, 8725 John J. Kingman Road, Suite 1644, Fort Belvoir, VA 22060–6221 or to the Privacy Act Office of the particular DLA field activity involved. Official mailing addresses are published as an appendix to DLA's compilation of systems of records notices.

Inquiry must contain the subject individual's full name and current mailing address to permit locating the record.

RECORD ACCESS PROCEDURE:

Individuals seeking access to information about themselves contained in this system of records should address written inquiries to the Privacy Act Office, Headquarters, Defense Logistics Agency, ATTN: DGA, 8725 John J. Kingman Road, Suite 1644, Fort Belvoir, VA 22060–6221 or to the Privacy Act Office of the particular DLA field activity involved. Official mailing addresses are published as an appendix to DLA's compilation of systems of records notices.

Inquiry must contain the subject individual's full name and current mailing address to permit locating the record.

CONTESTING RECORD PROCEDURES:

The DLA rules for accessing records, for contesting contents and appealing initial agency determinations are contained in 32 CFR part 323, or may be obtained from the Privacy Act Office, Headquarters, Defense Logistics Agency, ATTN: DGA, 8725 John J. Kingman Road, Suite 1644, Fort Belvoir, VA 22060–6221.

RECORD SOURCE CATEGORIES:

From the subject individual or the DLA organization publishing the document.

EXEMPTIONS CLAIMED FOR SYSTEM:

None.

[FR Doc. E9–12040 Filed 5–22–09; 8:45 am]

BILLING CODE 5001–06–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 June 25, 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: May 19, 2009.

Angela C. Arrington,

IC Clearance Official, Regulatory Information Management Services, Office of Management.

Office of Postsecondary Education

Type of Review: Extension.

Title: Application for Fulbright-Hays Seminars Abroad.

Frequency: Annually.

Affected Public: Individuals or household.

Reporting and Recordkeeping Hour Burden:

Responses: 400.

Burden Hours: 1,200.

Abstract: Application forms are to be used by applicants under the Fulbright-Hays Seminars Abroad Program which provides opportunities for U.S. educators to participate in short-term study seminars abroad in the subject areas of the social sciences, social studies and the humanities. The purpose of the program is for educators to obtain knowledge in these overseas seminars that they might not have been able to obtain otherwise, and produce that knowledge through a curriculum development project. This curricula will be accessible for other teachers in the public domain and able to be used in their classrooms.

This information collection is being submitted under the Streamlined Clearance Process for Discretionary Grant Information Collections (1894–0001). Therefore, the 30-day public comment period notice will be the only public comment notice published for this information collection.

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 4038. 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. E9–12074 Filed 5–22–09; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 2206–038]

Progress Energy Carolinas, Inc.; Notice of Application for Amendment of License and Soliciting Comments, Motions To Intervene, and Protests

May 18, 2009.

Take notice that the following hydroelectric application has been filed with the Commission and is available for public inspection:

a. *Application Type:* Non-project use of project lands.

b. *Project No.:* 2206–038.

c. *Date Filed:* April 14, 2009.

d. *Applicant:* Progress Energy Carolinas, Inc.

e. *Name of Project:* Yadkin-Pee Dee Hydroelectric Project.

f. *Location:* The proposed non-project use is on Lake Tillery in Stanly County, North Carolina.

g. *Filed Pursuant to:* Federal Power Act, 16 U.S.C. 791a–825r.

h. *Applicant Contact:* Larry Mann, Progress Energy Carolinas, Inc., 179 Tillery Dam Road, Mount Gilead, NC 27306, (919) 546–5300.

i. *FERC Contact:* Mark Carter, (202) 502–6554, *mark.carter@ferc.gov.*

j. *Deadline for Filing Comments, Motions to Intervene, and Protests:* June 18, 2009.

All documents (original and eight copies) should be filed with: Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

The Commission's Rules of Practice and Procedure require all interveners filing documents with the Commission to serve a copy of that document on each person whose name appears on the official service list for the project. Further, if an intervener files comments or documents with the Commission relating to the merits of an issue that may affect the responsibilities of a particular resource agency, it must also serve a copy of the document on that resource agency. A copy of any motion to intervene must also be served upon each representative of the Applicant specified in the particular application.

k. *Description of Request:* Progress Energy Carolinas, Inc. requests Commission authorization to grant Ken's Landing, LLC permission to expand an existing marina located on project lands. The expansion would include the removal of 26 boat slips (occupying an area of 6,360 square feet) and the addition of 40 new boat slips (occupying an area of 17,600 square feet). Prior to filing of the application, Ken's Landing, LLC consulted with appropriate agencies and other entities, including the U.S. Fish and Wildlife Service, North Carolina (NC) Wildlife Resources Commission, NC Department of Environment and Natural Resources, and NC Department of Cultural Resources.

l. *Locations of the Application:* A copy of the application is available for inspection and reproduction at the Commission's Public Reference Room, located at 888 First Street, NE., Room 2A, Washington, DC 20426, or by calling (202) 502–8371. This filing may also be viewed on the Commission's Web site at *http://www.ferc.gov* using the ''eLibrary'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. You may also register Online at *http://www.ferc.gov/docs-filing/esubscription.asp* to be notified via e-mail of new filings and issuances related to this or other pending projects. For assistance, call 1–866–208–3372 or e-mail *FERCOnlineSupport@ferc.gov,* for TTY, call (202) 502–8659. A copy is also available for inspection and reproduction at the address in item (h) above.

m. Individuals desiring to be included on the Commission's mailing list should so indicate by writing to the Secretary of the Commission.

n. *Comments, Protests, or Motions to Intervene:* Anyone may submit comments, a protest, or a motion to intervene in accordance with the requirements of Rules of Practice and Procedure, 18 CFR 385.210, .211, .214. In determining the appropriate action to take, the Commission will consider all protests or other comments filed, but only those who file a motion to intervene in accordance with the Commission's Rules may become a party to the proceeding. Any comments, protests, or motions to intervene must be received on or before the specified comment date for the particular application.

o. Any filings must bear in all capital letters the title ''COMMENTS'', ''PROTEST'', or ''MOTION TO INTERVENE'', as applicable, and the Project Number of the particular application to which the filing refers.

p. *Agency Comments:* Federal, State, and local agencies are invited to file comments on the described application. A copy of the application may be obtained by agencies directly from the Applicant. If an agency does not file comments within the time specified for filing comments, it will be presumed to have no comments. One copy of an agency's comments must also be sent to the Applicant's representatives.

q. Comments, protests and interventions may be filed electronically via the Internet in lieu of paper. See, 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site at *http://www.ferc.gov* under the ''e-Filing'' link.

Kimberly D. Bose,

Secretary.

[FR Doc. E9–12084 Filed 5–22–09; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 13429–000, Project No. 13455–000]

City of Burlington, IA; FFP Iowa 5, LLC Notice of Preliminary Permit Applications Accepted for Filing and Soliciting Comments, Motions To Intervene, and Competing Applications

May 15, 2009.

On April 8, 2009, the City of Burlington, Iowa filed an application, pursuant to section 4(f) of the Federal Power Act (FPA), proposing to study the feasibility of the City of Burlington Hydroelectric Project (Burlington Project) No. 13429, to be located on the Mississippi River, in Des Moines County, Iowa and Henderson County, Illinois. On April 29, 2009, FFP Iowa 5, LLC filed an application, pursuant to the FPA, proposing to study the feasibility of the Mississippi River Lock and Dam No. 18 Water Power Project (L&D 18 Project) No. 13455, to be located on the Mississippi River, in Des Moines County, Iowa.

The proposed Burlington and L&D 18 projects would be located at the existing U.S. Army Corps of Engineers (Corps) Lock and Dam No. 18 comprised of: (1) A 1,350-foot-long dam with 14 taintor gates and 3 roller gates and a 600-foot-long lock; and (2) a 12,152-acre reservoir with a normal pool elevation of 529.5 feet mean sea level.

The proposed Burlington Project would consist of: (1) Thirty submersible 500-kilowatt turbine generating units with total installed capacity of 15 megawatts (MW); (2) a 1-mile-long, 12.5-kilovolt (kV) transmission line; and (3) appurtenant facilities. The project would have an estimated average annual generation of 76,831 megawatts-hours (MWh), which would be sold to Alliant Energy. The project would be located along the western half of the Corps dam.

Applicant Contact: Mr. Doug Worden, City Manager, City of Burlington, Iowa, 400 Washington Street, Burlington, Iowa 52601, (319) 753–8120.

The proposed L&D 18 Project would consist of: (1) Twenty six Very Low Head generating units and 100 hydrokinetic generating units with a total installed capacity of 24.5 MW; (2) a 5.68-mile-long, 69-kV transmission line; and (3) appurtenant facilities. The project would have an estimated average annual generation of 119,500 MWh, which would be sold to Alliant Energy. The project would be located in the middle of the Mississippi River just downstream of the Corps dam.

Applicant Contact: Mr. Daniel R. Irvin, Free Flow Power Corporation, 33 Commercial Street, Gloucester, MA 01930, phone (978) 252–7631.

FERC Contact: Patrick Murphy, (202) 502–8755.

Deadline for filing comments, motions to intervene, competing applications (without notices of intent), or notices of intent to file competing applications: 60 days from the issuance of this notice. Comments, motions to intervene, notices of intent, and competing applications may be filed electronically via the Internet. See 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the ''e-Filing'' link. If unable to be filed electronically, documents may be paper-filed. To paper-file, an original and eight copies should be mailed to: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426. For more information on how to submit these types of filings please go to the Commission's Web site located at *http://www.ferc.gov/filing-comments.asp*. More information about this project can be viewed or printed on the ''eLibrary'' link of Commission's Web site at *http://www.ferc.gov/docs-filing/elibrary.asp*. Enter the docket number (P–13429 or 13455) in the docket number field to access the document. For assistance, call toll-free 1–866–208–3372.

Kimberly D. Bose,

Secretary.

[FR Doc. E9–12081 Filed 5–22–09; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 12731–002]

Natural Currents Energy Services, LLC; Notice of Intent To File License Application, Filing of Draft Application, Request for Waivers of Integrated Licensing Process Regulations Necessary for Expedited Processing of a Hydrokinetic Pilot Project License Application, and Soliciting Comments

May 15, 2009.

a. *Type of Filing:* Notice of Intent to File a License Application for an Original License for a Hydrokinetic Pilot Project.

b. *Project No.:* 12731–002.

c. *Date Filed:* May 15, 2009.

d. *Submitted By:* Natural Currents Energy Services, LLC.

e. *Name of Project:* Angoon Tidal Power Pilot Project.

f. *Location:* In Kootznahoo Inlet on the western shore of Admiralty Island, near the City of Angoon in the Skagway-Hoonah-Angoon Census Area of southeastern Alaska.

g. *Filed Pursuant to:* 18 CFR 5.3 of the Commission's regulations.

h. *Applicant Contact:* Roger Bason, President, Natural Currents Energy Services, 24 Roxanne Blvd., Highland, NY 12528; (845) 691–4008; *info@naturalcurrents.com*.

i. *FERC Contact:* Steve Hocking (502) 552–8753.

j. Natural Currents Energy Services, LLC (Natural Currents) has filed with the Commission: (1) A notice of intent (NOI) to file an application for an original license for a hydrokinetic pilot project and a draft license application with monitoring plans; (2) a proposed schedule; (3) a request to be designated as the non-Federal representative for section 7 of the Endangered Species Act consultation; and (4) a request to be designated as the non-Federal representative for section 106 consultation under the National Historic Preservation Act (collectively the pre-filing materials).

k. With this notice, we are soliciting comments on the pre-filing materials listed in paragraph j above, including the draft license application and monitoring plans. All comments should be sent to the address above in paragraph h. In addition, all comments (original and eight copies) must be filed with the Commission at the following address: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426. All filings with the Commission must include on the first page, the project name (Angoon Tidal Power Pilot Project) and number (P–12731–002), and bear the heading ''Comments on the proposed Angoon Tidal Power Pilot Project.'' Any individual or entity interested in submitting comments on the pre-filing materials must do so by July 14, 2009.

Comments may be filed electronically via the Internet in lieu of paper. The Commission strongly encourages electronic filings. *See* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site (*http://www.ferc.gov*) under the ''e-filing'' link.

l. With this notice, we are approving Natural Currents' request to be designated as the non-Federal representative for section 7 of the Endangered Species Act (ESA) and its request to initiate consultation under section 106 of the National Historic Preservation Act; and recommending that it begin informal consultation with: (a) The U.S. Fish and Wildlife Service and the National Marine Fisheries Service as required by section 7 of ESA; and (b) the Alaska State Historic Preservation Officer, as required by section 106, National Historical Preservation Act, and the implementing regulations of the Advisory Council on Historic Preservation at 36 CFR 800.2.

m. This notice does not constitute the Commission's approval of Natural Currents' request to use the Pilot Project Licensing Procedures. Upon its review of the project's overall characteristics relative to the pilot project criteria, the draft license application contents, and any comments filed, the Commission will determine whether there is adequate information to conclude the pre-filing process.

n. The proposed Angoon Tidal Power Pilot Project would consist of eight (8) 25-kw Red Hawk Tidal Turbines, with a combined maximum output of 200 kW for the pilot project. Initially, the turbines would be mounted on portable anchored barges to test different positions within the site for the best turbine performance. Following the location of the desired development site, tidal turbines will be mounted on constructed docks or piers secured to the solid, scoured, subsurface bedrock. The transmission intertie is to be determined. The estimated annual generation of the project would be 525,600 kilowatt-hours

o. A copy of the draft license application and all pre-filing materials are available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site (*http://www.ferc.gov*), using the ''eLibrary'' link. Enter the docket number, excluding the last three digits in the docket number field to access the document. For assistance, contact FERC Online Support at *FERCONlineSupport@ferc.gov* or toll free at 1–866–208–3676, of for TTY, (202) 502–8659.

p. Pre-filing process schedule. The pre-filing process will be conducted pursuant to the following tentative schedule. Revisions to the schedule below may be made based on staff's review of the draft application and any comments received.

Milestone	Date
Comments on pre-filing materials due	July 14, 2009.
Issuance of meeting notice (if needed)	July 29, 2009.
Public meeting/technical conference (if needed)	August 28, 2009.
Issuance of notice concluding pre-filing process and ILP waiver request determination	August 13, 2009 (if no meeting is needed). September 14, 2009 (if meeting is needed).

q. Register online at *http://ferc.gov/esubscribenow.htm* to be notified via e-mail of new filing and issuances related to this or other pending projects. For assistance, contact FERC Online Support.

Kimberly D. Bose,

Secretary.

[FR Doc. E9–12080 Filed 5–22–09; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket Nos. CP09–409–000]

Williston Basin Interstate Pipeline Company; Notice of Application

May 15, 2009.

Take notice that on May 12, 2009, Williston Basin Interstate Pipeline Company (Williston Basin), P.O. Box 5601, Bismarck North Dakota 58506–5601, filed in Docket Number CP09–409–000, pursuant to section 7(c) of the Natural Gas Act (NGA), an application for authority to acquire certain gas volumes to replenish lost cushion gas in its Elk Basin Storage Reservoir located in Park County, Wyoming and Carbon County, Montana. This filing is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the ''eLibrary'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll free at (866) 208–3676, or for TTY, contact (202) 502–8659.

Any questions regarding this Application or Petition should be directed to Keith A. Tiggelaar, Director of Regulatory Affairs for Williston Basin, 1250 West Century Avenue, Bismarck, North Dakota 58503, by phone at (701) 530–1560 or by e-mail at *keith.tiggelaar@wbip.com.*

Pursuant to section 157.9 of the Commission's rules, 18 CFR 157.9, within 90 days of this Notice the Commission staff will either: complete its environmental assessment (EA) and place it into the Commission's public record (eLibrary) for this proceeding, or issue a Notice of Schedule for Environmental Review. If a Notice of Schedule for Environmental Review is issued, it will indicate, among other milestones, the anticipated date for the Commission staff's issuance of the final environmental impact statement (FEIS) or EA for this proposal. The filing of the EA in the Commission's public record for this proceeding or the issuance of a Notice of Schedule for Environmental Review will serve to notify federal and state agencies of the timing for the completion of all necessary reviews, and the subsequent need to complete all federal authorizations within 90 days of the date of issuance of the Commission staff's FEIS or EA.

There are two ways to become involved in the Commission's review of this project. First, any person wishing to obtain legal status by becoming a party to the proceedings for this project should, on or before the below listed comment date, file with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, a motion to intervene in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 385.214 or 385.211) and the Regulations under the NGA (18 CFR 157.10). A person obtaining party status will be placed on the service list maintained by the Secretary of the Commission and will receive copies of all documents filed by the applicant and by all other parties. A party must submit 14 copies of filings made with the Commission and must mail a copy to the applicant and to every other party in the proceeding. Only parties to the proceeding can ask for court review of Commission orders in the proceeding.

However, a person does not have to intervene in order to have comments considered. The second way to participate is by filing with the Secretary of the Commission, as soon as possible, an original and two copies of comments in support of or in opposition to this project. The Commission will consider these comments in determining the appropriate action to be taken, but the filing of a comment alone will not serve to make the filer a party to the proceeding. The Commission's rules require that persons filing comments in opposition to the project provide copies of their protests only to the party or parties directly involved in the protest.

Persons who wish to comment only on the environmental review of this project should submit an original and two copies of their comments to the Secretary of the Commission. Environmental commenters will be placed on the Commission's environmental mailing list, will receive copies of the environmental documents, and will be notified of meetings associated with the Commission's environmental review process. Environmental commenters will not be required to serve copies of filed documents on all other parties. However, the non-party commenters will not receive copies of all documents filed by other parties or issued by the Commission (except for the mailing of environmental documents issued by the Commission) and will not have the right to seek court review of the Commission's final order.

Motions to intervene, protests and comments may be filed electronically via the Internet in lieu of paper; see, 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the ''e-Filing'' link. The Commission strongly encourages electronic filings.

Comment Date: May 29, 2009.

Kimberly D. Bose,

Secretary.

[FR Doc. E9–12078 Filed 5–22–09; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 12775–001]

City of Spearfish, South Dakota; Notice of Application Ready for Environmental Analysis and Soliciting Comments, Recommendations, Terms and Conditions, and Prescriptions

May 18, 2009.

Take notice that the following hydroelectric application has been filed with the Commission and is available for public inspection.

a. *Type of Application:* Major Project.

b. *Project No.:* 12775–001.

c. *Date Filed:* September 10, 2008.

d. *Applicant:* City of Spearfish, South Dakota.

e. *Name of Project:* Spearfish Hydroelectric Project.

f. *Location:* On Spearfish Creek in Lawrence County, South Dakota. The project occupies about 57.3 acres of United States lands within the Black Hills National Forest administered by the U.S. Forest Service.

g. *Filed Pursuant to:* Federal Power Act 16 U.S.C. 791 (a)–825(r).

h. *Applicant Contact:* Ms. Cheryl Johnson, Public Works Administrator, City of Spearfish, 625 Fifth Street, Spearfish, SD 57783; (605) 642–1333; or e-mail at *cherylj@city.spearfish.sd.us*.

i. *FERC Contact:* Steve Hocking at (202) 502–8753 or *steve.hocking@ferc.gov*.

j. Deadline for filing comments, recommendations, terms and conditions, and prescriptions is 60 days from the issuance of this notice; reply comments are due 105 days from the issuance date of this notice.

All documents (original and eight copies) should be filed with: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

The Commission's Rules of Practice require all intervenors filing documents with the Commission to serve a copy of that document on each person on the official service list for the project. Further, if an intervenor files comments or documents with the Commission relating to the merits of an issue that may affect the responsibilities of a particular resource agency, they must also serve a copy of the document on that resource agency.

Comments, recommendations, terms and conditions, and prescriptions may be filed electronically via the Internet in lieu of paper. The Commission strongly encourages electronic filings. See 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site (*http://www.ferc.gov/docs-filing/ferconline.asp*) under the ''e-filing'' link. For a simpler method of submitting text only comments, click on ''Quick Comment.''

k. This application has been accepted and is now ready for environmental analysis.

l. The existing Spearfish Project consists of: (1) A 130-foot-long gravity dam with an effective height of 4 feet; (2) a 0.32-acre reservoir; (3) a gatehouse next to the dam that contains four 2-foot-high, 4-foot-wide steel intake gates; (4) a 4.5-mile-long, 6.5-foot-wide, 9-foot-high concrete-lined aqueduct; (5) a forebay pond; (6) two 1,200-foot-long, 48-inch diameter, wood stave pipelines; (7) four 36-inch-diameter, 54-foot-high standpipe surge towers; (8) two 5,250-foot-long, 30- to 34-inch diameter steel penstocks; (9) a reinforced concrete powerhouse containing two Pelton turbines and two 2,000-kilowatt (kW) generators; and (10) appurtenant facilities.

m. A copy of the application is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the ''eLibrary'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at (866) 208–3676, or for TTY, (202) 502–8659. A copy is also available for inspection and reproduction at the address in item h above.

All filings must (1) bear in all capital letters the title ''COMMENTS,'' ''REPLY COMMENTS,'' ''RECOMMENDATIONS,'' ''TERMS AND CONDITIONS,'' or ''PRESCRIPTIONS;'' (2) set forth in the heading the name of the applicant and the project number of the application to which the filing responds; (3) furnish the name, address, and telephone number of the person submitting the filing; and (4) otherwise comply with the requirements of 18 CFR 385.2001 through 385.2005. All comments, recommendations, terms and conditions or prescriptions must set forth their evidentiary basis and otherwise comply with the requirements of 18 CFR 4.34(b). Agencies may obtain copies of the application directly from the applicant. Each filing must be accompanied by proof of service on all persons listed on the service list prepared by the Commission in this proceeding, in accordance with 18 CFR 4.34(b) and 385.2010.

You may also register online at *http://www.ferc.gov/docs-filing/esubscription.asp* to be notified via e-mail of new filings and issuances related to this or other pending projects. For assistance, contact FERC Online Support.

n. Public notice of the filing of the initial development application, which has already been given, established the due date for filing competing applications or notices of intent. Under the Commission's regulations, any competing development application must be filed in response to and in compliance with public notice of the initial development application. No competing applications or notices of intent may be filed in response to this notice.

o. A license applicant must file no later than 60 days following the date of issuance of this notice: (1) A copy of the water quality certification; (2) a copy of the request for certification, including proof of the date on which the certifying agency received the request; or (3) evidence of waiver of water quality certification.

p. *Procedural Schedule:* The application will be processed according to the following revised Hydro Licensing Schedule. Revisions to the schedule will be made as appropriate.

Milestone	Target date
All stakeholders: recommendations, terms, and conditions due	July 17, 2009.
All stakeholders: reply comments due	August 31, 2009.

Milestone	Target date
FERC issues draft environmental assess (EA)	November 3, 2009.
All stakeholders: draft EA comments due	December 3, 2009.
All stakeholders: modified terms and conditions due	February 1, 2010.
FERC issues final EA	March 30, 2010.

Kimberly D. Bose,
Secretary.
[FR Doc. E9–12088 Filed 5–22–09; 8:45 am]
BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. PF09–9–000]

ETC Tiger Pipeline, LLC; Notice of Intent To Prepare an Environmental Assessment for the Proposed Tiger Pipeline Project, Request for Comments on Environmental Issues and Notice of Public Scoping Meetings

May 15, 2009.

The staff of the Federal Energy Regulatory Commission (FERC or Commission) is in the process of preparing an environmental assessment (EA) that will discuss the environmental impacts that could result from the construction and operation of the Tiger Pipeline Project. The project is planned by ETC Tiger Pipeline, LLC (ETC Tiger) to transport natural gas from the Haynesville and Barnett Shale production areas to markets in the Midwest, Northeast, and Southeast.

This Notice of Intent (NOI) initiates the scoping process that will be used to gather input from the public and interested agencies on the project. Your input will help determine which issues will be evaluated in the EA. The staff will also use the scoping process to determine whether preparation of an environmental impact statement (EIS) is more appropriate for this project based upon the anticipated level of impacts. Please note that the scoping period for this project will close on June 29, 2009.

Comments may be submitted in written or verbal form. Further details on how to submit written comments are provided in the Public Participation section of this notice. In lieu of or in addition to sending written comments, the Commission Staff invites you to attend the public scoping meetings scheduled as follows.

Date and time	Location
Monday, June 8, 2009, 7 p.m. (CDT)	Delhi Civic Center, 232 Denver Street, Delhi, Louisiana 71232.
Tuesday, June 9, 2009, 7 p.m. (CDT)	Jackson Parish Community Center, 182 Industrial Drive, Jonesboro, Louisiana 71251.
Thursday, June 11, 2009, 7 p.m. (CDT)	Texas Country Music Hall of Fame, 300 West Panola Street, Carthage, Texas 75633.

Interested groups and individuals are encouraged to attend the meetings and to present comments on the environmental issues they believe should be addressed in the EA. A transcript of the meetings will be generated so that your comments will be accurately recorded.

The FERC will be the lead Federal agency in the preparation of an EA or EIS that will satisfy the requirements of the National Environmental Policy Act (NEPA) and will be used by the FERC to consider the environmental impacts that could result if the Commission issues ETC Tiger a Certificate of Public Convenience and Necessity (Certificate) under Section 7 of the Natural Gas Act.

This NOI is being sent to Federal, State, and local government agencies; elected officials; affected landowners; environmental and public interest groups; Indian Tribes and regional Native American organizations; commentors and other interested parties; and local libraries and newspapers. We [1] encourage government representatives to notify their constituents of this planned project and encourage them to comment on their areas of concern.

If you are a landowner receiving this notice, you may be contacted by an ETC Tiger representative about the acquisition of an easement to construct, operate, and maintain the proposed facilities. ETC Tiger would seek to negotiate a mutually acceptable agreement. However, if the project is approved by the FERC, that approval conveys with it the right of eminent domain. Therefore, if easement negotiations fail to produce an agreement, ETC Tiger could initiate condemnation proceedings in accordance with State law.

A fact sheet prepared by the FERC entitled ''An Interstate Natural Gas Facility on My Land? What Do I Need To Know?'' is available for viewing on the FERC Internet Web site (*http://www.ferc.gov/for-citizens/citizen-guides.asp*). This fact sheet addresses a number of typically asked questions, including the use of eminent domain and how to participate in FERC's proceedings.

Summary of the Proposed Project

ETC Tiger has announced its proposal to construct and operate a new natural gas pipeline and associated structures with a flow capacity of 2.0 billion cubic feet per day (Bcf/d). The project would consist of an approximate 174-mile, 42-inch-diameter pipeline running from the Carthage Hub in Panola County, Texas to the Perryville Hub in Richland Parish, Louisiana. ETC Tiger states that the Tiger Pipeline would transport natural gas from the growing Haynesville Shale production area to Midwest, Northeast, and Southeast markets through seven interconnects with other major interstate natural gas pipelines and one bi-directional interconnect with an existing intrastate pipeline at the Carthage Hub. In addition, the Tiger Pipeline would transport gas from the Barnett shale production area through its

[1] ''We,'' ''us,'' and ''our'' refer to the environmental staff of the FERC's Office of Energy Projects.

interconnection with Houston Pipe Line Company (Houston Pipe Line). The Project would provide a critical link between natural gas production in the Haynesville and adjacent Barnett shales and existing pipeline infrastructure in the region.

The Project is designed with a capacity of up to 1.0 Bcf/d from the Carthage Hub to Louisiana State Highway 789 and up to 2.0 Bcf/d from Louisiana State Highway 789 to the end of the pipeline. More specifically, ETC Tiger proposes the following facilities:

- 174 miles of 42-inch-diameter natural gas pipeline in Panola County, Texas; and Caddo, De Soto, Red River, Bienville, Jackson, Ouachita, and Richland Parishes, Louisiana;
- Four mainline compressor stations with approximately 113,000 combined horsepower (hp) in Panola County, Texas; and Red River Parish, Bienville Parish, and Jackson Parish, Louisiana;
- Ancillary facilities, including interconnects and pig [2] launchers and receivers;
- Receipt and delivery meter stations: 15 receipt meters, 7 delivery meters, and one bidirectional meter.

A location map depicting the proposed pipeline and compressor stations is attached to this NOI as Appendix 1.[3]

Land Requirements for Construction

As currently estimated by ETC Tiger, construction of the Tiger Pipeline Project would require about 3,407 acres of land, including pipeline, aboveground facilities, appurtenant facilities, pipe storage and contractor yards, and access roads. Following construction, about 1,588 acres would be used for operation of the project facilities. The areas disturbed during construction but not required for operation would generally be allowed to revert to pre-construction use and condition.

The EA Process

NEPA requires the Commission to take into account the environmental impacts that could result from an action whenever it considers the issuance of a Certificate. NEPA also requires us to discover and address concerns the public may have about proposals. This process is referred to as "scoping." The main goal of the scoping process is to focus the analysis in the EA on the important environmental issues. By this NOI, the Commission staff requests public comments on the scope of the issues to address in the EA. All comments received will be considered during the preparation of the EA. State and local government representatives are encouraged to notify their constituents of this proposed action and encourage them to comment on their areas of concern.

In the EA we will discuss impacts that could occur as a result of the construction and operation of the proposed Project under these general headings:

- Geology and soils;
- Land use;
- Water resources, fisheries, and wetlands;
- Cultural resources;
- Vegetation and wildlife;
- Air quality and noise;
- Endangered and threatened species; and
- Public safety.

We will also evaluate possible alternatives to the proposed Project or portions of the Project, and make recommendations on how to avoid, minimize, or mitigate impacts on the various resource areas.

Although no formal application has been filed, we have already initiated our NEPA review under the Commission's Pre-Filing Process. The purpose of the Pre-Filing Process is to encourage early involvement of interested stakeholders and to identify and resolve issues before an application is filed with the FERC. As part of our Pre-Filing Process review, we have begun to contact some Federal and State agencies to discuss their involvement in the scoping process and the preparation of the EA. In addition, representatives from the FERC participated in public open houses sponsored by ETC Tiger in the project area in April 2009 to explain the environmental review process to interested stakeholders.

Our independent analysis of the issues will be in the EA. Depending on the comments received during the scoping process, the EA may be published and mailed to Federal, State, and local agencies; public interest groups; interested individuals; affected landowners; newspapers; libraries; and the Commission's official service list for this proceeding. A comment period will be allotted for review following publication of the EA. We will consider all comments on the EA before we make our recommendations to the Commission. To ensure your comments are considered, please carefully follow the instructions in the Public Participation section below.

With this NOI, we are asking Federal, State, and local agencies with jurisdiction and/or special expertise with respect to environmental issues to formally cooperate with us in the preparation of the EA. These agencies may choose to participate once they have evaluated the proposal relative to their responsibilities. Additional agencies that would like to request cooperating agency status should follow the instructions for filing comments provided under the Public Participation section of this NOI.

Currently Identified Environmental Issues

We have already identified issues that we think deserve attention based on a preliminary review of the proposed facilities and our previous experience with similar projects in the region. This preliminary list of issues, which is presented below, may be revised based on your comments and our continuing analyses specific to the Tiger Pipeline Project.

- Potential effects on prime farmland soils and soils with a high potential for compaction.
- Potential effects on waterbodies designated under Federal and/or State programs, including the Sabine River, Saline Bayou, and Black Lake Bayou.
- Potential impacts to waterbird nesting areas along major river crossings.
- Potential impacts to wetland reserve program (WRP) and conservation reserve program (CRP) parcels of land.
- Potential effects on Federally and State-listed species, including interior least tern, red cockaded woodpecker, Louisiana black bear, pallid sturgeon, Earth fruit, and Louisiana pine snake.
- Potential impacts to existing land uses, including agricultural and forested lands.
- Potential visual effects of the aboveground facilities on surrounding areas.
- Alternative alignments for the pipeline route and alternative sites for the compressor stations.
- Assessment of the effect of the proposed project when combined with other past, present, or reasonably foreseeable future actions in the project area.

We usually limit the allowed construction right-of-way to a default width of 75 feet or that described in the Certificate application, unless modified by a Certificate condition. Both of the

[2] A pig is an internal tool that can be used to clean and dry a pipeline and/or to inspect it for damage or corrosion.

[3] The appendices referenced in this notice are not being printed in the **Federal Register**. Copies can be obtained from the Commission's Web site at the "eLibrary" link, from the Commission's Public Reference Room, or by calling (202) 502–8371. For instructions on connecting to "eLibrary", refer to the end of this notice. Copies of the appendices were sent to all those receiving this notice in the mail.

recently constructed large diameter (42-inch) natural gas pipelines in the proposed project area utilized a nominal 100-foot-wide construction right-of-way width in uplands and 75-foot-wide construction right-of-way in wetlands with additional temporary workspace, as required for specific construction requirements or techniques. ETC Tiger has proposed a range of right-of-way widths: 125 to 150 feet in uplands, depending on land use; and 75 to 125 feet in wetlands, depending on cover type and length of wetland crossing. We will be evaluating ETC Tiger's proposed construction right-of-way width configurations and justification and encourage your comments on this issue. A complete summary of the proposed right-of-way widths can be found in Appendix 1C of ETC Tiger's draft resource report 1 which can be obtained on the Commission's Web site through the ''eLibrary'' link.

Public Participation

You can make a difference by providing us with your specific comments or concerns about the Tiger Pipeline Project. Your comments should focus on the potential environmental effects, reasonable alternatives, and measures to avoid or lessen environmental impacts. The more specific your comments, the more useful they will be. To ensure that your comments are timely and properly recorded, please send in your comments so that they will be received in Washington, DC on or before June 29, 2009.

For your convenience, there are three methods you can use to submit your written comments to the Commission. In all instances please reference the project's Docket Number PF09–9–000 with your submission. The Commission encourages electronic filing of comments and has dedicated eFiling expert staff available to assist you at 202–502–8258 or *efiling@ferc.gov.*

(1) You may file your comments electronically by using the Quick Comment feature, which is located on the Commission's Internet Web site at *http://www.ferc.gov* under the link to Documents and Filings. A Quick Comment is an easy method for interested persons to submit text-only comments on a project;

(2) You may file your comments electronically by using the eFiling feature, which is located on the Commission's Internet Web site at *http://www.ferc.gov* under the link to Documents and Filings. eFiling involves preparing your submission in the same manner as you would if filing on paper, and then saving the file on your computer's hard drive. You will attach that file as your submission. New eFiling users must first create an account by clicking on ''Sign up'' or ''eRegister.'' You will be asked to select the type of filing you are making. A comment on a particular project is considered a ''Comment on a Filing;'' or

(3) You may file your comments via mail to the Commission by sending an original and two copies of your letter to: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 888 First St., NE., Room 1A, Washington, DC 20426.

Label one copy of the comments for the attention of Gas Branch 1, PJ–11.2.

Becoming an Intervenor

Once ETC Tiger formally files its application with the Commission you may want to become an ''intervenor,'' which is an official party to the proceeding. Intervenors play a more formal role in the process and are able to file briefs, appear at hearings, and be heard by the courts if they choose to appeal the Commission's final ruling. An intervenor formally participates in a Commission proceeding by filing a request to intervene. Instructions for becoming an intervenor are included in the User's Guide under the ''eFiling'' link on the Commission's Web site. Please note that you may *not* request intervenor status at this time. You must wait until a formal application is filed with the Commission.

Environmental Mailing List

Everyone who responds to this notice or provides comments throughout the EA process will be retained on the mailing list. If you do not want to send comments at this time but want to stay informed and receive a copy of the EA, you must return the Mailing List Retention Form (Appendix 2). If you do not send comments or return the Mailing List Retention Form asking to remain on the mailing list, you will be taken off the mailing list.

Additional Information

Additional information about the project is available from the Commission's Office of External Affairs at 1–866–208–FERC (3372), or on the FERC's Web site (*http://www.ferc.gov*) using the ''eLibrary'' link. Click on the ''eLibrary'' link, select ''General Search'', and enter the project docket number, excluding the last three digits (*i.e.,* PF09–9) in the ''Docket Number'' field. Be sure you have selected an appropriate date range. For assistance with ''eLibrary'', the ''eLibrary'' helpline can be reached at 1–866–208–3676, TTY (202) 502–8659, or by e-mail at *FERCOnlineSupport@ferc.gov*. The ''eLibrary'' link on the FERC Web site also provides access to the texts of formal documents issued by the Commission, such as orders, notices, and rule makings.

In addition, FERC now offers a free service called ''eSubscription'' that allows you to keep track of all formal issuances and submittals in specific dockets. This can reduce the amount of time you spend researching proceedings by automatically providing you with notification of these filings, document summaries, and direct links to the documents. To register for this service, go to *http://www.ferc.gov/esubscribenow.htm.*

Public meetings or site visits will be posted on the Commission's calendar located at *http://www.ferc.gov/EventCalendar/EventsList.aspx* along with other related information.

Finally, ETC Tiger has established a Web site for this project at *http://www.tigerpipeline.com*. The Web site includes a project overview, timeline, safety and environmental information, and answers to frequently asked questions. You can also request additional information by e-mailing or writing ETC Tiger directly:

Mr. Joey Mahmoud, ETC Tiger Pipeline, LLC, 711 Louisiana Street, Houston, Texas 77002–2716, *Joey.Mahmoud@energytransfer.com*, 281–714–2042.

R. Leon Banta, ETC Tiger Pipeline, LLC, 4300 Youree Drive, Building #1, Shreveport, LA 71105, *leon.banta@energytransfer.com,* 318–841–0266.

Kimberly D. Bose,

Secretary.

[FR Doc. E9–12075 Filed 5–22–09; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP08–465–000]

ANR Pipeline Company; Notice of Availability of the Environmental Assessment for the Proposed Wisconsin 2009 Expansion Project

May 15, 2009.

The staff of the Federal Energy Regulatory Commission (FERC or Commission) has prepared an environmental assessment (EA) of the Wisconsin 2009 Expansion Project proposed by ANR Pipeline Company (ANR) in the above-referenced docket.

The EA was prepared to satisfy the requirements of the National Environmental Policy Act (NEPA). The FERC staff concludes that approval of the proposed project, with appropriate mitigating measures, would not constitute a major Federal action significantly affecting the quality of the human environment.

The FERC is the lead agency for the preparation of the EA. The United States Environmental Protection Agency is a cooperating agency for the development of the EA. A cooperating agency has jurisdiction by law or special expertise with respect to the proposed action and participates in the NEPA analysis.

The EA assesses the potential environmental effects of the construction and operation of the proposed Wisconsin 2009 Expansion Project that includes the following facilities in Wisconsin:

- Construction of about 8.9 miles of 30-inch-diameter pipeline loop (Janesville Loop) in Rock County;
- Relocation of an existing pig receiver and appurtenances to the existing Janesville Compressor Station in Rock County;
- Installation of a new control valve at the existing Marshfield Compressor Station in Wood County, and Fairwater Meter Station in Columbia County; and
- Upgrading the existing Marshfield, North Wausau, and Randolph Meter Stations in Wood, Marathon, and Columbia Counties, respectively.

According to ANR, the purpose of the project is to accommodate the growing demand for natural gas on ANR's system and provide about 97,880,000 dekatherms per day of incremental firm capacity.

The EA has been placed in the public files of the FERC. A limited number of copies of the EA are available for distribution and public inspection at: Federal Energy Regulatory Commission, Public Reference Room, 888 First Street, NE., Room 2A, Washington, DC 20426, (202) 502–8371.

Copies of the EA have been mailed to federal, state, and local agencies, public interest groups, interested individuals, newspapers and libraries in the project area, and parties to this proceeding. Any person wishing to comment on the EA may do so. To ensure consideration prior to a Commission decision on the proposal, it is important that we receive your comments before the date specified below.

You can make a difference by providing us with your specific comments or concerns about the project. Your comments should focus on the potential environmental effects, reasonable alternatives, and measures to avoid or lessen environmental impacts. The more specific your comments, the more useful they will be. To ensure that your comments are timely and properly recorded, please send in your comments so that they will be received in Washington, DC on or before June 15, 2009.

For your convenience, there are three methods in which you can use to submit your comments to the Commission. In all instances please reference the project docket number (CP08–465–000) with your submission. The Commission encourages electronic filing of comments and has dedicated eFiling expert staff available to assist you at 202–502–8258 or *efiling@ferc.gov.*

(1) You may file your comments electronically by using the *Quick Comment* feature, which is located on the Commission's Internet Web site at *http://www.ferc.gov* under the link to *Documents and Filings.* A Quick Comment is an easy method for interested persons to submit text-only comments on a project;

(2) You may file your comments electronically by using the *eFiling* feature, which is located on the Commission's internet Web site at *http://www.ferc.gov* under the link to *Documents and Filings.* eFiling involves preparing your submission in the same manner as you would if filing on paper, and then saving the file on your computer's hard drive. You will attach that file as your submission. New eFiling users must first create an account by clicking on ''*Sign up*'' or ''*eRegister*''. You will be asked to select the type of filing you are making. A comment on a particular project is considered a ''Comment on a Filing;'' or

(3) You may file your comments via mail to the Commission by sending an original and two copies of your letter to: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 888 First St., NE., Room 1A, Washington, DC 20426;

Label one copy of the comments for the attention of Gas Branch 3, PJ11.3. Mail your comments promptly, so that they will be received in Washington, DC on or before June 15, 2009.

Comments will be considered by the Commission but will not serve to make the commentor a party to the proceeding. Any person seeking to become a party to the proceeding must file a motion to intervene pursuant to Rule 214 of the Commission's Rules of Practice and Procedures (18 CFR 385.214). Only intervenors have the right to seek rehearing of the Commission's decision. Further instructions for becoming an intervenor are included in the User's Guide under the ''e-filing'' link on the Commission's Web site (*http://www.ferc.gov*).

Affected landowners and parties with environmental concerns may be granted intervenor status upon showing good cause by stating that they have a clear and direct interest in this proceeding which would not be adequately represented by any other parties. You do not need intervenor status to have your comments considered.

Additional information about the project is available from the Commission's Office of External Affairs, at 1–866–208–FERC (3372) or on the FERC Internet website (*www.ferc.gov*) using the eLibrary link. Click on the eLibrary link, click on ''General Search'' and enter the docket number excluding the last three digits in the Docket Number field (i.e., CP08–465). Be sure you have selected an appropriate date range. For assistance, please contact FERC Online Support at *FercOnlineSupport@ferc.gov* or toll free at 1–866–208–3676, or for TTY, contact (202) 502–8659. The eLibrary link also provides access to the texts of formal documents issued by the Commission, such as orders, notices, and rulemakings.

In addition, the Commission now offers a free service called eSubscription which allows you to keep track of all formal issuances and submittals in specific dockets. This can reduce the amount of time you spend researching proceedings by automatically providing you with notification of these filings, document summaries and direct links to the documents. Go to *http://www.ferc.gov/esubscribenow.htm.*

Kimberly D. Bose,

Secretary.

[FR Doc. E9–12077 Filed 5–22–09; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. PF09–7–000]

Kern River Gas Transmission Company; Notice of Intent To Prepare an Environmental Impact Statement for the Apex Expansion Project, Request for Comments on Environmental Issues, and Notice of Joint Public Scoping Meetings

May 15, 2009.

The staff of the Federal Energy Regulatory Commission (FERC or Commission), the U.S. Department of Interior, Bureau of Land Management

(BLM), the U.S. Forest Service (FS), and Bureau of Reclamation (Reclamation) will prepare an environmental impact statement (EIS) that will discuss the environmental impacts that could result from the construction and operation of the Apex Expansion Project. The FERC is the lead federal agency for the preparation of the EIS, and the EIS will be used by the Commission in its decision making process to determine whether the project is in the public convenience and necessity. The project would involve Kern River Gas Transmission Company's (Kern River) planned construction and operation of a new natural gas pipeline in Morgan, Davis, and Salt Lake Counties, Utah.

This Notice of Intent (NOI) announces the opening of the scoping process used to gather input from the public and interested agencies on the project. Your input will help the Commission staff and cooperating agencies determine which issues need to be evaluated in the EIS. Please note that the scoping period will close on June 15, 2009.

Comments may be submitted in written or verbal form. Further details on how to submit written comments are provided in the Public Participation section of this notice. In lieu of or in addition to sending written comments, we invite you to attend the public scoping meetings scheduled as follows.

Date and time	Location
June 9, 2009 7 p.m. local time	Bountiful High School Auditorium, 695 S. Orchard Dr., Bountiful, UT 84010.
June 10, 2009 7 p.m. local time	Morgan County Courthouse Auditorium, 48 West Young Street, Morgan, UT 84050.

Interested groups and individuals are encouraged to attend the meetings and to present comments on the environmental issues they believe should be addressed in the EIS. A transcript of the meeting will be generated so that your comments will be accurately recorded.

This notice is being sent to the Commission's current environmental mailing list for this project, which includes: affected landowners; federal, state, and local government representatives and agencies; elected officials; environmental and public interest groups; Native American tribes; other interested parties in this proceeding; and local libraries and newspapers. We [1] encourage state and local government representatives to notify their constituents of the planned project and encourage them to comment on their areas of concern.

If you are a landowner receiving this notice, you may be contacted by a pipeline company representative about the acquisition of an easement to construct, operate, and maintain the planned facilities. The pipeline company would seek to negotiate a mutually acceptable agreement. However, if the project is approved by the Commission, that approval conveys with it the right of eminent domain. Therefore, if easement negotiations fail to produce an agreement, the pipeline company could initiate condemnation proceedings in accordance with state law.

A fact sheet prepared by the FERC entitled ''An Interstate Natural Gas Facility On My Land? What Do I Need To Know?'' is available for viewing on the FERC Internet Web site (*http://www.ferc.gov*). This fact sheet addresses a number of typically asked questions, including the use of eminent domain and how to participate in the Commission's proceedings.

Summary of the Proposed Project

Kern River has announced its plans to construct and operate approximately 29 miles of new 36-inch-diameter natural gas pipeline loop [2] in Morgan, Davis, and Salt Lake Counties, Utah (known as the Wasatch Loop). The planned Apex Expansion Project would also include:

- Construction of a new compressor station in Beaver County, Utah (Milford Compressor Station);
- Replacement of a compressor unit at the Fillmore Compressor Station in Millard County, Utah; and
- Additional compression at the following existing compressor stations, totaling 78,000 horsepower:
- Coyote Creek Compressor Station in Uinta County, Wyoming;
- Elberta Compressor Station in Utah County, Utah; and
- Dry Lake Compressor Station in Clark County, Nevada.

Location maps depicting the planned facilities are attached to this NOI as Appendix 1.[3]

Kern River is also considering an alternative pipeline route which would follow the planned route through the FS Ward Canyon utility corridor to Bountiful City where it would turn south onto Bountiful Boulevard for approximately 6 miles before rejoining the existing Kern River pipeline, thereafter following the planned route.

Land Requirements for Construction

Construction of the Apex Expansion Project would require about 356 acres of land for the pipeline. Following construction, about 178 acres would be used for the operation of the pipeline. The construction and operation of the Milford Compressor Station would require 30 acres on BLM land, and the upgrades and replacement activities at the existing compressor stations would require 20 acres on land already owned/leased by Kern River (The Dry Lake Compressor Station is also on land owned by the BLM). The area disturbed during construction but not required for operation would generally be allowed to revert to pre-construction condition.

The planned Wasatch Loop, some of which crosses land under the jurisdiction of the FS in the Uinta-Wasatch-Cache National Forest, would be located within and directly adjacent to the existing Kern River right-of-way. Kern River plans to align the loop with a typical offset of 35 feet from the existing pipeline to the extent practicable. The planned modifications to the four existing compressor stations would occur within the existing fence line of those facilities.

The EIS Process

The National Environmental Policy Act (NEPA) requires the Commission to take into account the environmental impacts that could result from an action whenever it considers the issuance of a Certificate of Public Convenience and

[1] ''We'', ''us'', and ''our'' refer to the environmental staff of the Office of Energy Projects (OEP).

[2] A loop is a segment of pipeline that is usually installed adjacent to an existing pipeline and connected to it at both ends. The loop allows more gas to be moved through the system.

[3] The appendices referenced in this notice are not being printed in the **Federal Register.** Copies of all appendices are available on the Commission's website at the ''eLibrary'' link or from the Commission's Public Reference Room, 888 First Street, NE., Washington, DC 20426, or call (202) 502–8371. For instructions on connecting to eLibrary refer to the last page of this notice. Copies of the appendices were sent to all those receiving this notice in the mail.

Necessity. NEPA also requires us to discover and address concerns the public may have about proposals. This process is referred to as ''scoping.'' The main goal of the scoping process is to focus the analysis in the EIS on the important environmental issues. By this NOI, the Commission staff requests public comments on the scope of the issues to address in the EIS. All comments received will be considered during the preparation of the EIS.

In the EIS we will discuss impacts that could occur as a result of the construction and operation of the planned project under these general headings:

- Geology and soils;
- Land use;
- Water resources, fisheries, and wetlands;
- Cultural resources;
- Vegetation and wildlife;
- Air quality and noise;
- Endangered and threatened species; and
- Public safety.

We will also evaluate possible alternatives to the planned project or portions of the project, and make recommendations on how to lessen or avoid impacts on the various resource areas.

Although no formal application has been filed, we have already initiated our NEPA review under the Commission's Pre-Filing Process. The purpose of the Pre-Filing Process is to encourage early involvement of interested stakeholders and to identify and resolve issues before an application is filed with the FERC. As part of our Pre-Filing Process review, we have begun to contact some federal and state agencies to discuss their involvement in the scoping process and the preparation of the EIS. In addition, representatives from the FERC participated in public open houses sponsored by Kern River in the project area in March 2009, to explain the environmental review process to interested stakeholders.

The planned Milford Compressor Station and associated access road and the Dry Lake Compressor Station would be located on federal lands for which the BLM has jurisdiction and/or special expertise with respect to environmental issues/impacts. The planned Wasatch Loop would cross federal lands under FS jurisdiction in the Uinta-Wasatch-Cache National Forest for which the FS would require a plan amendment to the 2003 Forest Plan. The planned route and the alternative route along Bountiful Boulevard would also cross federal lands under Reclamation jurisdiction. Kern River would seek a right-of-way grant amendment from the BLM for all federal lands crossed by the Project.

Our independent analysis of the issues will be included in a draft EIS. The draft EIS will be mailed to federal, state, and local government agencies; elected officials; affected landowners; environmental and public interest groups; Indian tribes and regional Native American organizations; commentors; other interested parties; local libraries and newspapers; and the FERC's official service list for this proceeding. A 45-day comment period will be allotted for review of the draft EIS and the proposed plan amendment. We will consider all timely comments on the draft EIS and revise the document, as necessary, before issuing a final EIS. To ensure that your comments are considered, please carefully follow the instructions in the Public Participation section of this NOI.

With this NOI, we are asking any other federal, state, and local agencies with jurisdiction and/or special expertise with respect to environmental issues to formally cooperate with us in the preparation of the EIS. These agencies may choose to participate once they have evaluated the proposal relative to their responsibilities. Additional agencies that would like to request cooperating agency status should follow the instructions for filing comments provided under the Public Participation section of this NOI. Currently, the BLM, FS, and Reclamation have expressed their intention to participate as cooperating agencies in the preparation of the EIS to satisfy their NEPA responsibilities for the portion of the Project on Federal lands.

Currently Identified Environmental Issues

We have already identified several issues that we think deserve attention based on a preliminary review of the planned facilities, comments made to us at Kern River's open houses, preliminary consultations with other agencies, and the environmental information provided by Kern River. This preliminary list of issues may be changed based on your comments and our analysis:

- Disturbance to residents along pipeline construction route, including noise and aesthetics;
- Impacts to the viewshed from construction activities and placement of aboveground facilities;
- Potential for geological hazards, including seismic activity, to have impacts on the pipeline;
- Impacts of the pipeline on cultural resources, including paleontological resources and historic trails;
- Impacts of the pipeline on recreation and scenic resources; and
- Possible disturbance to residents and impacts to the viewshed from construction activities on the alternative route along Bountiful Boulevard.

Public Participation

You can make a difference by providing us with your specific comments or concerns about the Apex Expansion Project. Your comments should focus on the potential environmental effects, reasonable alternatives, and measures to avoid or lessen environmental impacts. The more specific your comments, the more useful they will be. To ensure that your comments are timely and properly recorded, please send in your comments so that they will be received in Washington, DC on or before June 15, 2009.

For your convenience, there are three methods you can use to submit your written comments to the Commission. In all instances please reference the project docket number PF09–7–000 with your submission. The Commission encourages electronic filing of comments and has dedicated eFiling expert staff available to assist you at 202–502–8258 or*efiling@ferc.gov.*

(1) You may file your comments electronically by using the *Quick Comment* feature, which is located on the Commission's Internet Web site at *http://www.ferc.gov* under the link to *Documents and Filings.* A Quick Comment is an easy method for interested persons to submit text-only comments on a project;

(2) You may file your comments electronically by using the *eFiling* feature, which is located on the Commission's Internet Web site at *http://www.ferc.gov* under the link to *Documents and Filings.* eFiling involves preparing your submission in the same manner as you would if filing on paper, and then saving the file on your computer's hard drive. You will attach that file as your submission. New eFiling users must first create an account by clicking on ''*Sign up*'' or ''*eRegister.*'' You will be asked to select the type of filing you are making. A comment on a particular project is considered a ''Comment on a Filing;'' or

(3) You may file your comments via mail to the Commission by sending an original and two copies of your letter to: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 888 First St., NE., Room 1A, Washington, DC 20426.

Label one copy of the comments for the attention of Gas Branch 1, PJ–11.1.

Becoming an Intervenor

Once Kern River formally files its application with the Commission, you may want to become an ''intervenor,'' which is an official party to the proceeding. Intervenors play a more formal role in the process and are able to file briefs, appear at hearings, and be heard by the courts if they choose to appeal the Commission's final ruling. An intervenor formally participates in a Commission proceeding by filing a request to intervene. Instructions for becoming an intervenor are included in the User's Guide under the ''eFiling'' link on the Commission's Web site. Please note that you may not request intervenor status at this time; you must wait until the formal application for the Project is filed with the Commission.

Environmental Mailing List

An effort is being made to send this notice to all individuals, organizations, and government entities interested in and/or potentially affected by the planned project. This includes all landowners who are potential right-of-way grantors, whose property may be used temporarily for project purposes, or who own homes within certain distances (defined in the Commission's regulations) of aboveground facilities.

If you do not want to send comments at this time but still want to remain on our mailing list, please return the Information Request (Appendix 2). If you do not return the Information Request, you will be taken off the mailing list.

Availability of Additional Information

Additional information about the project is available from the Commission's Office of External Affairs, at 1–866–208–FERC or on the FERC Internet Web site (*http://www.ferc.gov*) using the eLibrary link. Click on the eLibrary link, click on ''General Search'' and enter the docket number excluding the last three digits in the Docket Number field. Be sure you have selected an appropriate date range. For assistance, please contact FERC Online Support at *FercOnlineSupport@ferc.gov* or toll free at 1–866–208–3676, or for TTY, contact (202) 502–8659. The eLibrary link also provides access to the texts of formal documents issued by the Commission, such as orders, notices, and rulemakings.

In addition, the Commission now offers a free service called eSubscription which allows you to keep track of all formal issuances and submittals in specific dockets. This can reduce the amount of time you spend researching proceedings by automatically providing you with notification of these filings, document summaries and direct links to the documents. Go to *http://www.ferc.gov/esubscribenow.htm.*

Public meetings or site visits will be posted on the Commission's calendar located at *http://www.ferc.gov/EventCalendar/EventsList.aspx* along with other related information.

Finally, to request additional information on the project or to provide comments directly to the project sponsor, you can contact Kern River directly by calling toll free at 1–888–222–1897. Also, Kern River has established an Internet Web site at *http://www.kernrivergas.com*, click on the ''Expansion Projects'' tab. The Web site includes a description of the Project, an overview map of the planned facilities, and links to related documents. Kern River will update the Web site as the environmental review of its project proceeds.

Kimberly D. Bose,

Secretary.

[FR Doc. E9–12082 Filed 5–22–09; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP09–58–000]

Rockies Express Pipeline LLC; Notice of Availability of the Environmental Assessment for the Proposed Meeker to Cheyenne Expansion Project

May 18, 2009.

The staff of the Federal Energy Regulatory Commission (FERC or Commission) has prepared the environmental assessment (EA) on the natural gas facilities proposed by Rockies Express Pipeline LLC (REX) in the above-referenced docket. REX's proposal (the Meeker to Cheyenne Expansion Project) would add one additional compressor unit to both the Big Hole and Arlington Compressor Stations in Moffat County, Colorado and Carbon County, Wyoming, respectively.

The EA was prepared to satisfy the requirements of the National Environmental Policy Act of 1969. The staff concludes that approval of the proposed project, with appropriate mitigating measures, would not constitute a major federal action significantly affecting the quality of the human environment.

The EA assesses the potential environmental effects of the construction and operation of the proposed Meeker to Cheyenne Expansion Project. The purpose of the project is to increase the capacity of the REX–Entrega Pipeline between the Meeker Hub (Rio-Blanco County, Colorado), the Wamsutter Hub (Sweetwater County, Wyoming), and the Cheyenne Hub (Weld County, Colorado) by 200,000 dekatherms per day.

The EA has been placed in the public files of the FERC. A limited number of copies of the EA are available for distribution and public inspection at: Federal Energy Regulatory Commission, Public Reference Room, 888 First Street, NE., Room 2A, Washington, DC 20426.

Copies of the EA have been mailed to federal, state, and local agencies; newspapers and libraries in the project area; parties to this proceeding; and those who have expressed an interest in this project by returning the Mailing List Form attached to the March 10, 2009 *Notice of Intent to Prepare an Environmental Assessment for the Proposed Meeker to Cheyenne Expansion Project and Request for Comments on Environmental Issues.*

Any person wishing to comment on the EA may do so. To ensure consideration prior to a Commission decision on the proposal, it is important that we receive your comments as specified below. Please carefully follow these instructions below to ensure that your comments are received in time and properly recorded.

You can make a difference by providing us with your specific comments or concerns about the Meeker to Cheyenne Expansion Project. Your comments should focus on the potential environmental effects, reasonable alternatives, and measures to avoid or lessen environmental impacts. The more specific your comments, the more useful they will be. To ensure that your comments are timely and properly recorded, please send in your comments so that they will be received in Washington, DC on or before June 17, 2009.

For your convenience, there are three methods in which you can use to submit your comments to the Commission. In all instances please reference the project docket number CP09–58–000 with your submission. The Commission encourages electronic filing of comments and has dedicated eFiling expert staff available to assist you at 202–502–8258 or*efiling@ferc.gov.*

(1) You may file your comments electronically by using the Quick Comment feature, which is located on the Commission's Internet Web site at*http://www.ferc.gov* under the link to Documents and Filings. A Quick

Comment is an easy method for interested persons to submit text-only comments on a project;

(2) You may file your comments electronically by using the eFiling feature, which is located on the Commission's Internet Web site at *http://www.ferc.gov* under the link to Documents and Filings. eFiling involves preparing your submission in the same manner as you would if filing on paper, and then saving the file on your computer's hard drive. You will attach that file as your submission. New eFiling users must first create an account by clicking on ''Sign up'' or ''eRegister.'' You will be asked to select the type of filing you are making. A comment on a particular project is considered a ''Comment on a Filing;'' or

(3) You may file your comments via mail to the Commission by sending an original and two copies of your letter to: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Room 1A, Washington, DC 20426.

Label one copy of the comments for the attention of the Gas Branch 1, PJ–11.1

Comments will be considered by the Commission but will not serve to make the commentor a party to the proceeding. Any person seeking to become a party to the proceeding must file a motion to intervene pursuant to Rule 214 of the Commission's Rules of Practice and Procedures (18 CFR 385.214).[1] Only intervenors have the right to seek rehearing of the Commission's decisions.

Affected landowners and parties with environmental concerns may be granted intervenor status upon showing good cause by stating that they have a clear and direct interest in this proceeding which would not be adequately represented by any other parties. You do not need intervenor status to have your comments considered.

Additional information about the project is available from the Commission's Office of External Affairs at 1–866–208–FERC or on the FERC Internet Web site (*http://www.ferc.gov*) using the eLibrary link. Click on the eLibrary link, then on ''General Search'' and enter the docket number excluding the last three digits in the docket number field (i.e., CP09–58). Be sure you have selected an appropriate date range. For assistance, please contact FERC Online Support at *FercOnlineSupport@ferc.gov* or toll free at 1–866–208–3676, or for TTY, contact (202) 502–8659. The eLibrary link on the FERC Internet Web site also provides access to the texts of formal documents issued by the Commission, such as orders, notices, and rulemakings.

[1] Interventions may also be filed electronically via the Internet in lieu of paper. See the previous discussion of filing comments electronically.

In addition, the Commission offers a free service called eSubscription which allows you to keep track of all formal issuances and submittals in specific dockets. This can reduce the amount of time you spend researching proceedings by automatically providing you with notifications of these filings, document summaries and direct links to the documents. Go to *http://www.ferc.gov/esubscribenow.htm.*

Kimberly D. Bose,

Secretary.

[FR Doc. E9–12089 Filed 5–22–09; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP07–52–000; Docket Nos. CP07–53–000, CP07–53–001]

Downeast LNG, Inc. and Downeast Pipeline, LLC.; Notice of Availability of the Draft Environmental Impact Statement for the Proposed Downeast LNG Project

May 15, 2009.

The staff of the Federal Energy Regulatory Commission (Commission or FERC) has prepared this draft Environmental Impact Statement (EIS) to address Downeast LNG, Inc.'s and Downeast Pipeline, LLC.'s (hereafter collectively referred to as Downeast) proposed liquefied natural gas (LNG) terminal, natural gas pipeline, and associated facilities in the above-referenced docket. The Downeast LNG Project (Project) would be located in Washington County, Maine.

The draft EIS was prepared to satisfy the requirements of the National Environmental Policy Act (NEPA). The U.S. Coast Guard; U.S. Army Corps of Engineers; National Oceanic and Atmospheric Administration, National Marine Fisheries Service; U.S. Environmental Protection Agency; and the Maine Department of Environmental Protection are cooperating agencies for the development of this EIS. A cooperating agency has jurisdiction by law or special expertise with respect to potential environmental impacts associated with the proposal and is involved in the NEPA analysis.

Based on the analysis included in the EIS, the FERC staff concludes construction and operation of the Downeast LNG Project would result in some adverse environmental impacts. However, most of these impacts would be reduced to less-than-significant levels with the implementation of Downeast's proposed mitigation measures and the additional measures we recommend in the EIS.

The Project would establish a LNG marine terminal in New England capable of unloading cargo from LNG vessels, storing up to 320,000 cubic meters of LNG in specially designed tanks, vaporizing the LNG back into natural gas, and providing an average sendout of 500 million cubic feet of natural gas per day to the New England region's interstate pipeline grid. Downeast's proposed 29.8-mile-long pipeline would transport natural gas from the LNG terminal to an interconnect point with Maritimes and Northeast Pipeline's L.L.C. (M&NE) existing pipeline system near the town of Baileyville, Maine. Downeast states that the Project would provide an additional supply source of natural gas to meet increasing demand and increase the reliability of the interstate gas delivery system in New England.

The draft EIS addresses the potential environmental effects of construction and operation of the following facilities proposed by Downeast:

- A new marine terminal that would include a 3,862-foot-long pier with a single berth and vessel mooring system, intended to handle LNG vessels ranging from 70,000 to 165,000 cubic meters in capacity, with future expansion capabilities to handle vessels with 220,000 cubic meters of cargo capacity;
- two full-containment LNG storage tanks, each with a nominal usable storage capacity of 160,000 cubic meters;
- LNG vaporization and processing equipment;
- piping, ancillary buildings, safety systems, and other support facilities;
- a 29.8-mile-long, 30-inch-diameter underground natural gas pipeline;
- natural gas metering facilities located at the LNG terminal site; and
- various ancillary facilities including pigging[1] facilities and three mainline block valves.

The Project would also include the transit of LNG vessels through both United States and Canadian waters to and from the LNG terminal in Robbinston, Maine. The intended vessel transit routes include the waters of the Gulf of Maine, Bay of Fundy, Grand Manan Channel, Head Harbor Passage,

[1] A ''pig'' is a tool for cleaning and inspecting the inside of a pipeline.

Friar Roads, Western Passage, and Passamaquoddy Bay. The draft EIS also includes information regarding potential modifications and expansions of the M&NE pipeline system to transport the natural gas volumes that would be supplied by the Downeast sendout pipeline.

The draft EIS has been placed in the public files of the FERC and is available for distribution and public inspection at: Federal Regulatory Energy Commission, Public Reference Room, 888 First St., NE., Room 2A, Washington, DC 20426, (202) 502–8371.

Only volume 1 of the draft EIS, containing text of the analysis, was printed in hard copy. Volume 2, containing additional appendices, was produced as .pdf files on a compact disk (CD) that can be read by a computer with a CD-ROM drive. A limited number of hard copies and CDs of the draft EIS are available from the FERC's Public Reference Room, identified above. This draft EIS is also available for public viewing on the FERC's Internet Web site at *http://www.ferc.gov*, via the eLibrary link, and at project area libraries listed in Appendix A of the draft EIS.

Copies of the document have been mailed to Federal, State, and local government agencies; elected officials; Native American tribes and regional organizations; local libraries and newspapers; intervenors in the FERC's proceeding; and other interested parties (*i.e.,* individuals and groups who provided scoping comments or asked to remain on the mailing list). All parties on the mailing list were sent a CD of the draft EIS. A hard copy was also mailed to those who specifically requested one.

Comment Procedures and Public Meetings

Any person wishing to comment on the draft EIS is encouraged to do so. Your comments should focus on the potential environmental effects, reasonable alternatives, and measures to avoid or lessen environmental impacts. The more specific your comments, the more useful they will be. To ensure consideration prior to a Commission decision on the proposal, it is important that your comments be received before July 6, 2009. Please carefully follow the instructions below so that your comments are properly recorded.

For your convenience, there are three methods you can use to submit your comments to the Commission. In all instances, please reference the Project Docket Numbers CP07–52–000, CP07–53–000, and CP07–53–001 with your submission. The Commission encourages electronic filing of comments and has dedicated eFiling expert staff available to assist you at (202) 502–8258 or *efiling@ferc.gov*.

(1) You may file your comments electronically by using the *Quick Comment* feature, which is located on the Commission's internet Web site at *http://www.ferc.gov* under the link to *Documents and Filings*. A Quick Comment is an easy method for interested persons to submit text-only comments on a project;

(2) You may file your comments electronically by using the *eFiling* feature, which is located on the Commission's Internet Web site at *http://www.ferc.gov* under the link to *Documents and Filings*. eFiling involves preparing your submission in the same manner as you would if filing on paper, and then saving the file on your computer's hard drive. You will attach that file as your submission. New eFiling users must first create an account by clicking on ''*Sign up*'' or ''*eRegister*.'' You will be asked to select the type of filing you are making. A comment on a particular project is considered a ''Comment on a Filing;'' or

(3) You may file your comments via mail to the Commission by sending an original and two copies of your letter to: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 888 First St., NE., Room 1A, Washington, DC 20426.

Label one copy of the comments for the attention of Gas Branch 3, PJ–11.3. Mail your comments promptly, so that they will be received in Washington, DC on or before July 6, 2009.

In addition to or in lieu of sending written comments, we invite you to attend the public comment meeting we will conduct in the Project area. The meeting will begin at 7 p.m. (EST), and is scheduled as follows:

Date: Tuesday, June 16, 2009.

Location: Robbinston Grade School Cafeteria 904 U.S. Route 1 Robbinston, Maine (207) 454–3694.

This public meeting will be posted on the FERC's calendar located at *http://www.ferc.gov/EventCalendar/EventsList.aspx*. Interested groups and individuals are encouraged to attend and present written or oral comments on the draft EIS. Transcripts of the meetings will be prepared.

After the comments are reviewed, any significant new issues are investigated, and necessary modifications are made to the draft EIS, a final EIS will be published and distributed. The final EIS will contain our responses to timely comments filed on the draft EIS that are related to environmental issues.

Comments will be considered by the Commission and the cooperating agencies but will not serve to make the commentor a party to the proceeding. Any person seeking to become a party to the proceeding must file a motion to intervene pursuant to Rule 214 of the Commission's Rules of Practice and Procedure (Title 18 CFR 385.214). Only intervenors have the right to seek rehearing of the Commission's decision. Further instructions for becoming an intervenor are included in the User's Guide under the ''e-filing'' link on the Commission's Web site (*http://www.ferc.gov*). You do not need intervenor status to have your comments considered.

Additional information about the Project is available from the Commission's Office of External Affairs at 1–866–208–FERC (3372). The administrative public record for this proceeding to date is on the FERC Internet Web site (*http://www.ferc.gov*). Click on the eLibrary link, click on ''General Search,'' and enter the docket number excluding the last three digits in the Docket Number field (*i.e.,* CP07–52). Be sure you have selected an appropriate date range. For assistance, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll free at 1–866–208–3676, or for TTY, contact (202) 502–8659. The eLibrary link on the FERC Internet Web site also provides access to the texts of formal documents issued by the Commission, such as orders, notices, and rulemakings.

In addition, the Commission now offers a free service called eSubscription that allows you to keep track of all formal issuances and submittals in specific dockets. This can reduce the amount of time you spend researching proceedings by automatically providing you with notification of these filings, document summaries, and direct links to the documents. To register for this service, go to the eSubscription link on the FERC Internet Web site (*http://www.ferc.gov/docs-filing/esubscription.asp*).

Kimberly D. Bose,

Secretary.

[FR Doc. E9–12076 Filed 5–22–09; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER09–1132–000]

Palmco Power NJ, LLC; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization

May 18, 2009.

This is a supplemental notice in the above-referenced proceeding, of Palmco Power NJ, LLC's application for market-based rate authority, with an accompanying rate schedule, noting that such application includes a request for blanket authorization, under 18 CFR Part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization, under 18 CFR Part 34, of future issuances of securities and assumptions of liability is June 8, 2009.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at *http://www.ferc.gov.* To facilitate electronic service, persons with Internet access who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically should submit an original and 14 copies of the intervention or protest to the Federal Energy Regulatory Commission, 888 First St., NE., Washington, DC 20426.

The filings in the above-referenced proceeding(s) are accessible in the Commission's eLibrary system by clicking on the appropriate link in the above list. They are also available for review in the Commission's Public Reference Room in Washington, DC. There is an eSubscription link on the Web site that enables subscribers to receive e-mail notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Kimberly D. Bose,

Secretary.

[FR Doc. E9–12086 Filed 5–22–09; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER09–1131–000]

Palmco Power CT, LLC; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization

May 18, 2009.

This is a supplemental notice in the above-referenced proceeding, of Palmco Power CT, LLC's application for market-based rate authority, with an accompanying rate schedule, noting that such application includes a request for blanket authorization, under 18 CFR Part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and § 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization, under 18 CFR Part 34, of future issuances of securities and assumptions of liability is June 8, 2009.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at *http://www.ferc.gov.* To facilitate electronic service, persons with Internet access who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically should submit an original and 14 copies of the intervention or protest to the Federal Energy Regulatory Commission, 888 First St., NE., Washington, DC 20426.

The filings in the above-referenced proceeding(s) are accessible in the Commission's eLibrary system by clicking on the appropriate link in the above list. They are also available for review in the Commission's Public Reference Room in Washington, DC. There is an eSubscription link on the Web site that enables subscribers to receive e-mail notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Kimberly D. Bose,

Secretary.

[FR Doc. E9–12085 Filed 5–22–09; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER09–1117–000]

NGP Blue Mountain I LLC; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization

May 15, 2009.

This is a supplemental notice in the above-referenced proceeding of NGP Blue Mountain I LLC's application for market-based rate authority, with an accompanying rate tariff, noting that such application includes a request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability, is June 4, 2009.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at *http://www.ferc.gov.* To facilitate electronic service, persons with Internet access who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically should submit an original and 14 copies of the intervention or protest to the Federal Energy Regulatory Commission, 888 First St., NE., Washington, DC 20426.

The filings in the above-referenced proceeding are accessible in the Commission's eLibrary system by clicking on the appropriate link in the above list. They are also available for review in the Commission's Public Reference Room in Washington, DC. There is an eSubscription link on the Web site that enables subscribers to receive e-mail notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov.* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Kimberly D. Bose,

Secretary.

[FR Doc. E9–12079 Filed 5–22–09; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER09–1133–000]

Palmco Power PA, LLC; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization

May 18, 2009.

This is a supplemental notice in the above-referenced proceeding, of Palmco Power PA, LLC's application for market-based rate authority, with an accompanying rate schedule, noting that such application includes a request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability is June 8, 2009.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at *http://www.ferc.gov.* To facilitate electronic service, persons with Internet access who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically should submit an original and 14 copies of the intervention or protest to the Federal Energy Regulatory Commission, 888 First St., NE., Washington, DC 20426.

The filings in the above-referenced proceeding(s) are accessible in the Commission's eLibrary system by clicking on the appropriate link in the above list. They are also available for review in the Commission's Public Reference Room in Washington, DC. There is an eSubscription link on the Web site that enables subscribers to receive e-mail notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov.* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Kimberly D. Bose,

Secretary.

[FR Doc. E9–12087 Filed 5–22–09; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. AD09–6–000]

Pipeline Siting and Stakeholder Involvement Workshop; Notice of Pipeline Siting and Stakeholder Involvement Workshop

May 15, 2009.

On June 1, 2009, the Federal Energy Regulatory Commission (FERC or Commission) will hold a workshop, hosted by Commissioner Philip Moeller, on natural gas pipeline siting. The workshop will focus on the importance of pipeline companies working collaboratively with affected stakeholders throughout the environmental review and certification process to successfully site new pipeline infrastructure. A case study of a recent major pipeline project will be presented by the pipeline company representatives. In addition, a panel of outreach experts from the industry and FERC staff will provide perspectives on innovative approaches to stakeholder outreach and the importance of outreach efforts in the siting process.

The workshop will be held at the Commission's Headquarters, 888 First St., NE., Washington, DC 20426 in the Commission Meeting Room from 1 p.m. until 4:15 p.m. EST. All interested parties may attend. The workshop will not be transcribed, and telephone participation will not be available.

Commission workshops and conferences are accessible under section 508 of the Rehabilitation Act of 1973. For accessibility accommodations please send an e-mail to *accessibility@ferc.gov* or call toll free 1–866–208–3372 (voice) or 202–208–8659 (TTY), or send a FAX to 202–208–2106 with the required accommodations.

The agenda for the siting workshop is attached. For additional information concerning this event, please contact Lauren O'Donnell at 202–502–8325 or Berne Mosley at 202–502–8625.

Kimberly D. Bose,

Secretary.

Pipeline Siting and Stakeholder Involvement Workshop Agenda

1 p.m. Welcome and Opening Remarks.

1:15 p.m. Case Study of CenterPoint Energy's Carthage to Perryville Pipeline Project.

Debbie Ristig, Vice President, Engineering and Compliance, CenterPoint Energy.

2:15 p.m. Break.

2:30 p.m. Stakeholder Outreach Panel Discussion.

Julee Stephenson, Director, Regulatory and Government Affairs, NiSource Gas Transmission & Storage.

Cindy Ivey, Manager, Public Outreach, Transcontinental Gas Pipeline.

Susan Waller, Vice President, Stakeholder Outreach, Spectra Energy Transmission.

Douglas Sipe, Outreach Coordinator, Federal Energy Regulatory Commission.

3:45 p.m. Questions and Closing Remarks.

4:15 p.m. Adjourn.

[FR Doc. E9–12083 Filed 5–22–09; 8:45 am]

BILLING CODE 6717–01–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OEI–2009–0328, FRL–8909–4]

Agency Information Collection Activities; Proposed Collection; Comment Request; Regulations.gov Information Collection; OMB Control No. 2025–0008, EPA ICR No. 2357.02

AGENCY: Environmental Protection Agency (EPA).

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 to replace an emergency Information Collection Request (ICR) to the Office of Management and Budget (OMB). This emergency ICR was approved by OMB on May 18, 2009. Before submitting this 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 before July 27, 2009.

ADDRESSES: Submit your comments, referencing Docket ID No. EPA–HQ–OEI–2009–0328, to (1) EPA online using *www.regulations.gov* (our preferred method), by e-mail to *brackett.shanita@epa.gov*, by mail to: EPA Docket Center, Environmental Protection Agency, mail code 28221T, 1200 Pennsylvania Ave., NW., Washington, DC 20460, or by hand delivery: EPA Docket Center, EPA West Bldg, Room 3334, 1301 Constitution Ave. NW., Washington, DC 20460. Such deliveries are only accepted during the Docket's normal hours of operation.

FOR FURTHER INFORMATION CONTACT:
Shanita Brackett, OEI/OIC/CStD at the Environmental Protection Agency, 1200 Pennsylvania Ave., NW., (MC 2822–T), Washington, DC 20460; telephone number (202) 566–1008; fax number(202) 566–1611: e-mail address: *brackett.shanita@epa.gov.*

SUPPLEMENTARY INFORMATION:

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 ICR title on the first page of your response. You may also provide the **Federal Register** citation.

What Information Collection Activity or ICR Does this Apply To?

Title: Regulations.gov Information Collection.

OMB Control Number: 2025–0008.

Abstract: In response to the Presidential memorandum, the eRulemaking Program will launch the *Regulations.gov* 'feedback exchange' Web site in May 2009. This interactive Web site will showcase new technologies being considered for *Regulations.gov.* The 'feedback exchange' will serve as a learning laboratory for open government, enabling the public to provide input on the *Regulations.gov* interface, build a community of practice on the Federal regulatory development process, and ensure that the eRulemaking Program can efficiently manage federal resources by testing new tools before they are launched.

The Regulations.gov 'feedback exchange' Web site will provide the public with a preview of new technologies considered for Regulations.gov. It will also enable the public to provide feedback on these technologies. Technologies considered for the Regulations.gov 'feedback exchange' include: User Profiles; Comment Threads and Wikis; Ratings, Polls, and Tagging; an interactive Educational Tool; and an Information Export capability. These technologies will be deployed iteratively, with components deployed upon the site's release in May 2009 and during subsequent upgrades to the Web site. User profiles enable the public to register on the site and pre-load submitter information for later use as well as save their own personalized searches, RSS feeds, and e-mail alerts without the use of persistent cookies. Comment Threads allow the public to enter into virtual conversations with one another about a topic. Wikis enable the public to collaboratively develop and modify narrative descriptions about a topic. Ratings and Polls allow the public to indicate a preference for a topic or issue via the selection of stars or thumbs up/thumbs down icons which graphically provide an at-a-glance indication of public sentiment and can simplify navigation. Tagging provides the public with the ability to tag or label information they or someone else has posted to the site to ease navigation and to promote the formation of common interest categories. The Educational Tool will inform the public about the Federal rulemaking process through interactive text and images. The Data Export capability enables the public to download and review the contents of a rulemaking docket as well as mix and match such information with other information in a new way (also known as a ''mash-up''). The *Regulations.gov* ''feedback exchange'' will rely on feedback from Government, Industry, Academia and Citizenry to improve *Regulations.gov* as time goes on.

Burden Statement: The annual public reporting and recordkeeping burden for this collection of information is estimated to average 35 hours per year. 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:

Affected Entities: Anyone that chooses to visit Regulations.gov.

Estimated Total Number of Potential Respondents: 1,000.

Estimated Total Number of Potential Responses: 7,000.

Frequency of Response: Occasionally.

Estimated Total Annual Burden Hours: 35 hours.

Estimated Total Annual Capital and Operations and Maintenance Costs: $ 0.

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 person listed under **FOR FURTHER INFORMATION CONTACT**.

Dated: May 19, 2009.

John Moses,

Director, Collection Strategies Division.

[FR Doc. E9–12132 Filed 5–22–09; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OPP–2009–0008; FRL–8414–4]

SFIREG Full Committee Meeting

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: The Association of American Pesticide Control Officials (AAPCO)/ State FIFRA Issues Research and Evaluation Group (SFIREG) will hold a 2–day meeting, beginning on June 22, 2009 and ending June 23, 2009. This notice announces the location and times for the meeting and sets forth the tentative agenda topics.

DATES: The meeting will be held on Monday, June 22, 2009 from 8:30 a.m. to 5:00 p.m. and 8:30 a.m to 12 noon on Tuesday June 23, 2009

To request accommodation of a disability, please contact the person listed under **FOR FURTHER INFORMATON CONTACT**, preferably at least 10 days prior to the meeting, to give EPA as much time as possible to process your request.

ADDRESSES: The open meeting will be held at EPA. One Potomac Yard (South Bldg.) 2777 Crystal Dr., Arlington VA. 1st and 4th Floor South Conference Room.

FOR FURTHER INFORMATION CONTACT: Ron Kendall, Field and External Affairs Division (7506P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001; telephone number: (703 305–5561 fax number: (703) 308–1850; e-mail address: *kendall.ron@epa.gov*. or Grier Stayton, SFIREG Executive Secretary, P.O. Box 466, Milford DE 19963; telephone number (302) 422–8152; fax (302) 422–2435; e-mail address*: grierstaytonaapco-sfireg@comcast.net*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this Action Apply to Me?

You may be potentially affected by this action if you are interested in SFIREG information exchange relationship with EPA regarding important issues related to human health, environmental exposure to pesticides, and insight into EPA's decision-making process. You are invited and encouraged to attend the meetings and participate as appropriate. Potentially affected entities may include, but are not limited to:

Those persons who are or may be required to conduct testing of chemical substances under the Federal Food, Drug and Cosmetics Act (FFDCA), or the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA).

B. How Can I Get Copies of this Document and Other Related Information?

1. *Docket.* EPA has established a docket for this action under docket ID number EPA–HQ–OPP–2008–0143. Publicly available docket materials are available either in the electronic docket at *http://www.regulations.gov*, or, if only available in hard copy, at the Office of Pesticide Programs (OPP) Regulatory Public Docket in Rm. S–4400, One Potomac Yard (South Bldg.), 2777 S. Crystal Dr., Arlington, VA. The hours of operation of this Docket Facility are from 8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. The Docket Facility telephone number is (703) 305–5805.

2. *Electronic access.* You may access this **Federal Register** document electronically through the EPA Internet under the ''**Federal Register**'' listings at *http://www.epa.gov/fedrgstr*.

II. Background

Topics may include but are not limited to:

1. Regional Reports and Issue Papers
2. TPPC Report
3 AAPSE Report
4. 24C Discussion
5. Acetochlor label changes
6. Chemigation - pdate and Discussion
7. NPDES - latest activity update and discussion
8. Endangered Species Protection Program - recent happenings and label language
9. Indemnification Statements on Section 3 labels
10. Strychnine and its classification status
11. PPDC Update
12. FIFRA Strategic Plan - State Volunteers
13. Boiler plate language - groundwater and other statements
14. EQIWC Update
15. POM Update
16. Total Release Foggers - Update
17. EUP Guidelines for States
18. Drift Language Improvement
19. Investigative Field Notes Policy
20. Web Distributed Labels
21. Green Labeling
22. Discussion on the 2011–2013 state/tribal grant guidance, potential focus areas, process, etc.
23. Bed Bug Forum - results/action items
24. Atrazine Water Quality Criteria - May SAP

III. How Can I Request to Participate in this Meeting?

This meeting is open for the public to attend. You may also submit a request to participate in this meeting to the person listed under **FOR FURTHER INFORMATION CONTACT**. Do not submit any information in your request that is considered CBI. Requests to participate in the meeting, identified by docket ID number EPA–HQ–OPP–2009–0008, must be received on or before June 16, 2009 **Federal Register**.

List of Subjects

Environmental protection.

Dated: May 18, 2009.

W. R. Diamond,

Director, Field and External Affairs Division

[FR Doc. E9–12141 Filed 5–22–09; 8:45 am]

BILLING CODE 6560–50–S

FEDERAL DEPOSIT INSURANCE CORPORATION

Agency Information Collection Activities: Proposed Collection Renewals; Comment Request

AGENCY: Federal Deposit Insurance Corporation (FDIC).

ACTION: Notice and request for comment.

SUMMARY: The FDIC, 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 continuing information collections, as required by the Paperwork Reduction Act of 1995 (44 U.S.C. chapter 35). Currently, the FDIC is soliciting comments on renewal of five information collections described below.

DATES: Comments must be submitted on or before July 27, 2009.

ADDRESSES: Interested parties are invited to submit written comments to the FDIC by any of the following methods:

- *http://www.FDIC.gov/regulations/laws/federal/notices.html.*
- *E-mail: comments@fdic.gov.* Include the name of the collection in the subject line of the message.
- *Mail:* Leneta G. Gregorie (202–898–3719), Counsel, Room F–1064, Federal Deposit Insurance Corporation, 550 17th Street, NW., Washington, DC 20429.
- *Hand Delivery:* Comments may be hand-delivered to the guard station at the rear of the 17th Street Building (located on F Street), on business days between 7 a.m. and 5 p.m.

All comments should refer to the relevant OMB control number. A copy of the comments may also be submitted to the OMB desk officer for the FDIC: Office of Information and Regulatory Affairs, Office of Management and Budget, New Executive Office Building, Washington, DC 20503.

FOR FURTHER INFORMATION CONTACT: Leneta Gregorie, at the FDIC address above.

SUPPLEMENTARY INFORMATION: Proposal to renew the following currently approved collections of information:

1. *Title:* Application Pursuant to Section 19 of the Federal Deposit Insurance Act.

OMB Number: 3064–0018.

Form Number: FDIC 6710/07.

Frequency of Response: On occasion.

Affected Public: Insured depository institutions.

Estimated Number of Respondents: 14.

Estimated Time per Response: 16 hours.

Total Annual Burden: 224 hours.

General Description of Collection: Section 19 of the Federal Deposit Insurance Act (FDI), 12 U.S.C. 1829, requires the FDIC's consent prior to any participation in the affairs of an insured depository institution by a person who has been convicted of crimes involving dishonesty or breach of trust. To obtain that consent, an insured depository institution must submit an application to the FDIC for approval on Form FDIC 6710/07.

2. *Title:* Procedures for Monitoring Bank Protection Act Compliance.

OMB Number: 3064–0095.

Form Numbers: None.

Frequency of Response: On occasion.

Affected Public: Insured state nonmember banks.

Estimated Number of Respondents: 5,110.

Estimated Time per Response: 0.5 hours.

Total Annual Burden: 2,555 hours.

General Description of Collection: The Bank Protection Act of 1968 (12 U.S.C. 1881–1884) requires each Federal supervisory agency to promulgate rules establishing minimum standards for security devices and procedures to discourage financial crime and to assist in the identification of persons who commit such crimes. To avoid the necessity of constantly updating a technology-based regulation, the FDIC takes a flexible approach to implementing this statute. It requires each insured nonmember bank to designate a security officer who will administer a written security program. The security program shall: (1) Establish procedures for opening and closing for business and for safekeeping valuables; (2) establish procedures that will assist in identifying persons committing crimes against the bank; (3) provide for initial and periodic training of employees in their responsibilities under the security program; and (4) provide for selecting, testing, operating and maintaining security devices as prescribed in the regulation. In addition, the FDIC requires the security officer to report at least annually to the bank's board of directors on the effectiveness of the security program.

3. *Title:* Activities and Investments of Insured State Banks.

OMB Number: 3064–0111.

Form Numbers: None.

Frequency of Response: On occasion.

Affected Public: Insured state nonmember banks.

Estimated Number of Respondents: 20.

Estimated Time per Response: 8 hours.

Total Annual Burden: 160 hours.

General Description of Collection: With certain exceptions, section 24 of the FDI Act (12 U.S.C. 1831a) limits the direct equity investments of state chartered banks to equity investments that are permissible for national banks. In addition, the statute prohibits an insured state bank from directly engaging as principal in any activity that is not permissible for a national bank or indirectly through a subsidiary in an activity that is not permissible for a subsidiary of a national bank unless the bank meets its minimum capital requirements and the FDIC determines that the activity does not pose significant risk to the Deposit Insurance Fund. The FDIC can make such a determination for exception by regulation or by order. The FDIC's implementing regulation for section 24 is 12 CFR part 362. It details the activities that insured state nonmember banks or their subsidiaries may engage in, under certain criteria and conditions, and identifies the information that banks must furnish to the FDIC in order to obtain the FDIC's approval or non-objection.

4. *Title:* Mutual-to-Stock Conversions of State Savings Banks.

OMB Number: 3064–0117.

Form Numbers: None.

Frequency of Response: On occasion.

Affected Public: Insured State chartered savings banks that are not members of the Federal Reserve System proposing to convert from mutual to stock form of ownership.

Estimated Number of Respondents: 10.

Estimated Time per Response: 50 hours.

Total Annual Burden: 500 hours.

General Description of Collection: Sections 303.161 and 333.4 of Title 12 of the Code of Federal Regulations require State savings banks that are not members of the Federal Reserve System to file with the FDIC a notice of intent to convert to stock form and to provide copies of documents filed with State and Federal banking and/or securities regulators in connection with the proposed conversion.

5. *Title:* Privacy of Consumer Financial Information.

OMB Number: 3064–0136.

Form Numbers: None.

Frequency of Response: On occasion.

Affected Public: Insured State nonmember banks.

Estimated Number of Respondents: Initial notice, 208; annual notice and change in terms 5,138; opt-out notice, 873.

Estimated Average Time per Response: Initial notice, 80 hours; annual notice and change in terms, 8 hours; opt-out notice, 8 hours.

Estimated Number of Responses: 328,600.

Total Annual Burden: 64,728 hours.

General Description of Collection: The elements of this collection are required under section 504 of the Gramm-Leach-Bliley Act, Public Law l06–102. The collection mandates notice requirements and restrictions on a financial institution's ability to disclose nonpublic personal information about consumers to nonaffiliated third parties.

Request for Comment

Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the FDIC's functions, including whether the information has practical utility; (b) the accuracy of the estimates of the burden of the information collection, including the validity of the methodology and assumptions used; (c) ways to enhance the quality, utility, and clarity of the information to be collected; and (d) ways to minimize the burden of the information collection on respondents, including through the use of automated collection techniques or other forms of information technology. All comments will become a matter of public record.

Dated at Washington, DC, this 19th day of May, 2009.

Federal Deposit Insurance Corporation.

Robert E. Feldman,

Executive Secretary.

[FR Doc. E9–12043 Filed 5–22–09; 8:45 am]

BILLING CODE 6714–01–P

FEDERAL DEPOSIT INSURANCE CORPORATION

Agency Information Collection Activities: Submission for OMB Review; Comment Request

AGENCY: Federal Deposit Insurance Corporation (FDIC).

ACTION: Notice of information collections to be submitted to OMB for review and approval under the Paperwork reduction Act of 1995.

SUMMARY: In accordance with requirements of the Paperwork reduction Act of 1995 (44 U.S.C. chapter 35), the FDIC hereby gives notice that it plans to submit to the Office of Management and Budget (OMB) a request for OMB review and renewal of the collections of information described below:

DATES: Comments must be submitted on or before June 25, 2009.

ADDRESSES: Interested parties are invited to submit written comments to FDIC by any of the following methods. All comments should refer to the name of the collection as well as the OMB control number(s):

- Web site: *http://www.FDIC.gov/regulations/laws/federal/notices.html*.
- *E-mail: Comments@FDIC.gov*. Include the name of the collection in the subject line of the message.
- *Mail:* Herbert J. Messite, Counsel, 202.898.6834, Legal Division, Federal Deposit Insurance Corporation, 550 17th Street, NW., Washington, DC 20429.
- *Hand Delivery:* Comments may be hand-delivered to the guard station at the rear of the 550 17th Street Building (located on F Street), on business days between 7 a.m. and 5 p.m.

Public Inspection: All comments received will be posted without change to *http://www.fdic.gov/regulations/laws/federal/propose.html* including any personal information provided. Comments may be inspected at the FDIC Public Information Center, Room E–1002, 3501 Fairfax Drive, Arlington, VA 22226, between 9 a.m. and 5 p.m. on business days.

Comments may also be submitted to the OMB desk officer for the FDIC: Office of Information and Regulatory Affairs, Office of Management and Budget, New Executive Office Building, Room 10235, 727 17th Street, NW., Washington, DC 20503.

FOR FURTHER INFORMATION CONTACT: Herbert J. Messite at the address identified above.

SUPPLEMENTARY INFORMATION: Proposal to renew the following currently approved collections of information:

1. *Title:* Recordkeeping and Confirmation Requirements for Securities Transactions.

OMB Number: 3064–0028.

Frequency of Response: On occasion.

Affected Public: Business or other financial institutions.

Estimated Number of Respondents: 4470.

Estimated Time per Response: 27.91 hours.

Total Annual Burden: 124,758 hours.

General Description of Collection: The information collection requirements are contained in 12 CFR part 344. The regulation's purpose is to ensure that purchasers of securities in transactions affected by insured state nonmember banks are provided with adequate records concerning the transactions. The regulation is also designed to ensure that insured State nonmember banks maintain adequate records and controls with respect to the securities transactions they effect.

2. *Title:* Certification of Compliance with Mandatory Bars to Employment.

OMB Number: 3064–0121.

Form Number: FDIC 7300/06.

Frequency of Response: On occasion.

Affected Public: Business or other financial institutions.

Estimated Number of Respondents: 600.

Estimated Time per Response: 10 minutes.

Total Annual Burden: 99.96 hours.

General Description of Collection: Prior to an offer of employment, job applicants to the FDIC must sign a certification that they have not been convicted of a felony or been in other circumstances that prohibit person from becoming employed by or providing services to FDIC.

Request for Comment

Comments are invited on: (a) Whether the collections of information are necessary for the proper performance of the FDIC's functions, including whether the information has practical utility; (b) the accuracy of the estimates of the burden of the information collections, 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 information collection on respondents, including through the use of automated collection techniques or other forms of information technology. All comments will become a matter of public record.

Dated at Washington, DC, this 19th day of May, 2009.

Federal Deposit Insurance Corporation.

Robert E. Feldman,

Executive Secretary.

[FR Doc. E9–12045 Filed 5–22–09; 8:45 am]

BILLING CODE 6714–01–P

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 June 9, 2009.

A. Federal Reserve Bank of Chicago (Colette A. Fried, Assistant Vice President) 230 South LaSalle Street, Chicago, Illinois 60690–1414:

1. West Suburban Bancorp, Inc., Lombard, Illinois; to engage *de novo* in extending credit and servicing loans, pursuant to section 225.28(b)(1) of Regulation Y.

Board of Governors of the Federal Reserve System, May 20, 2009.

Robert deV. Frierson,

Deputy Secretary of the Board.

[FR Doc. E9–12110 Filed 5–22–09; 8:45 am]

BILLING CODE 6210–01–S

DEPARTMENT OF DEFENSE

GENERAL SERVICES ADMINISTRATION

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION

[OMB Control No. 9000–0060]

Federal Acquisition Regulation; Information Collection; Accident Prevention Plans and Recordkeeping

AGENCY: Department of Defense (DOD), General Services Administration (GSA), and National Aeronautics and Space Administration (NASA).

ACTION: Notice of request for reinstatement of an information collection requirement regarding an existing OMB clearance.

SUMMARY: Under the provisions of the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35), the Federal Acquisition Regulation (FAR), Regulatory Secretariat will be submitting to the Office of Management and Budget (OMB) a request to review and approve a reinstatement of a previously approved information collection requirement concerning Accident Prevention Plans and Recordkeeping.

Public comments are particularly invited on: Whether this collection of information is necessary; whether it will have practical utility; whether our estimate of the public burden of this collection of information is accurate, and based on valid assumptions and methodology; ways to enhance the quality, utility, and clarity of the information to be collected; and ways in which we can minimize the burden of the collection of information on those who are to respond, through the use of appropriate technological collection techniques or other forms of information technology.

DATES: Submit comments on or before July 27, 2009.

ADDRESSES: Submit comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to: General Services Administration, Regulatory Secretariat (VPR), 1800 F Street, NW., Room 4041, Washington, DC 20405. Please cite OMB Control No. 9000–0060, Accident Prevention Plans and Recordkeeping, in all correspondence.

FOR FURTHER INFORMATION CONTACT: Mr. Ernest Woodson, Procurement Analyst, Contract Policy Division, GSA, telephone (202) 501–3775.

SUPPLEMENTARY INFORMATION:

A. Purpose

The FAR clause at 52.236–13, Accident Prevention requires Federal construction contractors to keep records of accidents incident to work performed under the contract that result in death, traumatic injury, occupational disease or damage to property, materials, supplies or equipment. Records of personal inquiries are required by OSHA (OMB Control No. 1220–0029). The records maintained by the contractor are used to evaluate compliance and may be used in workmen's compensation cases. The FAR requires records of damage to property, materials, supplies or equipment to provide background information when claims are brought against the Government.

If the contract involves work of a long duration, the contractor must submit a written proposed plan for implementing the clause. The Accident Prevention Plan, for projects that are hazardous or of long duration, is analyzed by the contracting officer along with the agency safety representatives to determine if the proposed plan will meet the requirements of safety regulations and applicable statutes. The Accident Prevention Plan is placed in the official contract file by the contracting officer for reference.

B. Annual Reporting Burden

Respondents: *2,106.*

Responses per Respondent: *2.*

Annual Responses: *4,212.*

Hours per Response: *2.*

Total Burden Hours: *8,424.*

Obtaining Copies of Proposals: Requesters may obtain a copy of the information collection documents from the General Services Administration, Regulatory Secretariat (VPR), Room 4041, 1800 F Street, NW., Washington, DC 20405, telephone (202) 501–4755. Please cite OMB Control No. 9000–0060, Accident Prevention Plans and Recordkeeping, in all correspondence.

Dated: May 19, 2009.

Edward Loeb,

Acting Director, Office of Acquisition Policy.

[FR Doc. E9–12071 Filed 5–22–09; 8:45 am]

BILLING CODE 6820–EP–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

HIT Standards Committee Schedule for the Assessment of HIT Policy Committee Recommendations

AGENCY: Office of the National Coordinator for Health Information Technology (ONC), HHS.

ACTION: Notice.

SUMMARY: Section 3003(b)(3) of the American Recovery and Reinvestment Act of 2009 mandates that the HIT Standards Committee develop a schedule for the assessment of policy recommendations developed by the HIT Policy Committee and publish it in the **Federal Register**. This notice fulfills the requirements of Section 3003(b)(3) and shall be updated at least annually.

In anticipation of receiving recommendations originally developed by the HIT Policy Committee, the Standards Committee has created three (3) workgroups or subcommittees to analyze the areas of clinical quality, clinical operations, and privacy and security.

HIT Standards Committee Schedule for the Assessment of HIT Policy Committee Recommendations:

The National Coordinator will establish priority areas based in part of recommendations received from the HIT Policy Committee regarding health information technology standards, implementation specifications, and/or certification criteria. Once the HIT Standards Committee is informed of those priority areas, it will:

(A) Direct the appropriate subcommittee to develop a report for the HIT Standards Committee, to the extent possible, within 90 days, which will include among other items the following:

(1) An assessment of what standards, implementation specifications, and certification criteria are currently available to meet the priority area;

(2) an assessment of where gaps exist (*i.e.*, no standard is available or harmonization is required because more than one standard exists) and identify potential organizations that have the capability to address those gaps; and

(3) a timeline, which will also account for NIST testing where appropriate, for the HIT Standards Committee to issue recommendation(s) to the National Coordinator.

(B) Upon receipt of a subcommittee report, the HIT Standards Committee will:

(1) accept the timeline provided by the subcommittee, and if necessary, revise it; and

(2) assign subcommittee(s) to conduct research and solicit testimony, where appropriate, and issue recommendations to the full committee, in a timely manner.

(C) Advise the National Coordinator, consistent with the accepted timeline in (B)(1) and after NIST testing, where appropriate, on standards, implementation specifications, and/or certification criteria, for the National Coordinator's review and possible endorsement to the Secretary of Health and Human Services.

FOR FURTHER INFORMATION CONTACT: ONC/HHS, Judith Sparrow, (202) 205–4528.

Authority: The American Recovery and Reinvestment Act of 2009 (Pub. L. 111–5), section 3003.

Dated: May 18, 2009.

David Blumenthal,

National Coordinator for Health Information Technology, Office of the National Coordinator for Health Information Technology.

[FR Doc. E9–12175 Filed 5–20–09; 4:15 pm]

BILLING CODE 4150–45–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: Drug and Alcohol Services Information System (DASIS)—(OMB No. 0930–0106)—Revision

The DASIS consists of three related data systems: The Inventory of Substance Abuse Treatment Services (I–SATS); the National Survey of Substance Abuse Treatment Services (N–SSATS), and the Treatment Episode Data Set (TEDS). The I–SATS includes all substance abuse treatment facilities known to SAMHSA. The N–SSATS is an annual survey of all substance abuse treatment facilities listed in the I–SATS. The TEDS is a compilation of client-level admission data and discharge data submitted by States on clients treated in facilities that receive State funds. Together, the three DASIS components provide information on the location, scope and characteristics of all known drug and alcohol treatment facilities in the United States, the number of persons in treatment, and the characteristics of clients receiving services at publicly-funded facilities. This information is needed to assess the nature and extent of these resources, to identify gaps in services, to provide a database for treatment referrals, and to assess demographic and substance-related trends in treatment. In addition, several National Outcome Measures (NOMS) data elements are collected in TEDS to assess the performance of the Substance Abuse Prevention and Treatment (SAPT) Block Grant.

The request for OMB approval will include a request to conduct the 2010 through 2012 N–SSATS and Mini–N–SSATS. The Mini–N–SSATS is a procedure for collecting services data from newly identified facilities between main cycles of the survey and will be used to improve the listing of treatment facilities in the on-line treatment facility Locator. The N–SSATS questionnaire is expected to remain unchanged except for minor modifications to wording. If there is a need for substantial revision to the N–SSATS questionnaire during the period of this clearance, a supplemental request for clearance will be submitted.

The OMB request will also include the collection of TEDS data, including the addition of two new NOMS data elements to the TEDS client-level record. To the extent that states already collect the elements from their treatment providers, the following elements will be included in the TEDS data collection: Frequency of attendance at self-help programs in past 30 days at admission; and frequency of attendance at self-help programs in past 30 days at discharge. No significant changes are expected in the other DASIS activities.

Estimated annual burden for the DASIS activities is shown below:

Type of respondent and activity	Number of respondents	Responses per respondent	Hours per response	Total burden hours
STATES				
TEDS Admission Data	52	4	6	1,248
TEDS Discharge Data	52	4	8	1,664

Type of respondent and activity	Number of respondents	Responses per respondent	Hours per response	Total burden hours
TEDS Discharge Crosswalks	5	1	10	50
I–SATS Update [1]	56	70	.08	314
State Subtotal	56			3,276
FACILITIES				
I–SATS Update [2]	200	1	.08	16
N–SSATS questionnaire	17,000	1	.67	11,390
Augmentation screener	1,000	1	.08	80
Mini–N–SSATS	2,000	1	.42	840
Facility Subtotal	20,200			12,326
TOTAL	20,256			15,602

[1] States forward to SAMHSA information on newly licensed/approved facilities and on changes in facility name, address, status, etc. This is submitted electronically by nearly all States.

[2] Facilities forward to SAMHSA information on new facilities and on changes to existing facilities. This is submitted by e-mail by nearly all facilities.

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: May 14, 2009.

Elaine Parry,

Director, Office of Program Services.

[FR Doc. E9–12122 Filed 5–22–09; 8:45 am]

BILLING CODE 4162–20–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Administration for Children and Families

Proposed Information Collection Activity; Comment Request

Proposed Projects

Title: Tribal TANF Financial Report (ACF–196T).

OMB No.: 0970–0345.

Description: Tribes use Form ACF–196T to report expenditures for the Tribal TANF grant. Authority to collect and report this information is found in the Personal Responsibility and Work Opportunity Reconciliation Act of 1996 (PRWORA), Public Law 104–193. Tribal entities with approved Tribal plans for implementation of the TANF program are required by Section 412(h) of the Social Security Act to report financial data. Form ACF–196T provides for the collection of data regarding Federal expenditures. Failure to collect this data would seriously compromise the Administration for Children and Families' (ACF) ability to monitor expenditures. This information is also used to estimate outlays and may be used to prepare ACF budget submissions to Congress. Financial management of the program would be seriously compromised if the expenditure data were not collected.

45 CFR part 286 subpart E requires the strictest controls on funding requirements, which necessities review of documentation in support of Tribal expenditures for reimbursement. Comments received from previous efforts to implement a similar Tribal TANF report Form ACF–196T were used to guide ACF in the development of the product presented with this submittal.

The American Recovery and Reinvestment Act (ARRA) of 2009, Public Law 111–5 has authorized emergency TANF funds to be awarded to States, Tribes, and Territories who meet certain eligibility requirements written in the legislation. TANF Policy Announcement TANF–ACF–PA–2009–01 provides additional guidance on eligibility requirements. Recipients of ARRA funds are to report spending and performance data to Federal agencies quarterly for posting on the public Web site, ''Recovery.gov.'' Federal agencies are required to collect ARRA expenditures data and the data must be clearly distinguishable from the regular TANF (non-ARRA) funds. Therefore, in order to meet this data collection requirement, the ACF–196T has been modified with the addition of two line items and a column to report ARRA expenditures. The collection and posting of this data is to allow the public to see where their tax dollars are spent.

Respondents: All Tribal TANF Agencies.

ANNUAL BURDEN ESTIMATES

Instrument	Number of respondents	Number of responses per respondent	Average burden hours per Response	Total burden hours
ACF–196T	56	4	8	1,792

Estimated Total Annual Burden Hours: 1,792.

In compliance with the requirements of Section 506(c)(2)(A) of the Paperwork Reduction Act of 1995, the Administration for Children and Families is soliciting public comment on the specific aspects of the information collection described above. Copies of the proposed collection of information can be obtained and comments may be forwarded by writing to the Administration for Children and Families, Office of Administration, Office of Information Services, 370 L'Enfant Promenade, SW., Washington, DC 20447, Attn: ACF Reports Clearance Officer. E-mail address:

infocollection@acf.hhs.gov. All requests should be identified by the title of the information collection.

The Department specifically requests comments on: (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the proposed collection of information; (c) 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. Consideration will be given to comments and suggestions submitted within 60 days of this publication.

Dated: May 20, 2009.

Janean Chambers,

Reports Clearance Officer.

[FR Doc. E9–12104 Filed 5–22–09; 8:45 am]

BILLING CODE 4184–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Administration for Children and Families

Proposed Information Collection Activity; Comment Request

Proposed Projects

Title: ACF Uniform Project Description.

OMB No.: 0970–0139.

Description: The Administration for Children and Families (ACF) has more than 40 discretionary grant programs. The proposed information collection form would be a uniform discretionary application form eligible for use by grant applicants to submit project information in response to ACF program announcements. ACF would use this information, along with other OMB-approved information collections, to evaluate and rank applicants and protect the integrity of the grantee selection process. All ACF discretionary grant programs would be eligible but not required to use this application form. The application consists of general information and instructions; the Standard Form 424 series that requests basic information, budget information and assurances; the Project Description requesting the applicant to describe how these objectives will be achieved; along with assurances and certifications. Guidance for the content of information requested in the Project Description is found in OMB Circular A–102 and 45 CFR Part 74.

Respondents: Applicants for ACF Discretionary Grant Programs.

ANNUAL BURDEN ESTIMATES

Instrument	Number of respondents	Number of responses per respondent	Average burden hours per response	Total burden hours
UPD	11,588	1	40	463,520

Estimated Total Annual Burden Hours: 463,520.

In compliance with the requirements of Section 506(c)(2)(A) of the Paperwork Reduction Act of 1995, the Administration for Children and Families is soliciting public comment on the specific aspects of the information collection described above. Copies of the proposed collection of information can be obtained and comments may be forwarded by writing to the Administration for Children and Families, Office of Administration, Office of Information Services, 370 L'Enfant Promenade, SW., Washington, DC 20447, Attn: ACF Reports Clearance Officer. E-mail address: *infocollection@acf.hhs.gov.* All requests should be identified by the title of the information collection.

The Department specifically requests comments on: (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the proposed collection of information; (c) 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. Consideration will be given to comments and suggestions submitted within 60 days of this publication.

Dated: May 20, 2009.

Janean Chambers,

Reports Clearance Officer.

[FR Doc. E9–12093 Filed 5–22–09; 8:45 am]

BILLING CODE 4184–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare and Medicaid Services

[CMS–2487–PN]

Medicare and Medicaid Programs; Application by the American Osteopathic Association for Continued Deeming Authority for Ambulatory Surgical Centers

AGENCY: Centers for Medicare & Medicaid Services, HHS.

ACTION: Proposed notice.

SUMMARY: This proposed notice acknowledges the receipt of a deeming application from the American Osteopathic Association (AOA) for continued recognition as a national accrediting organization for ambulatory surgical centers (ASCs) that wish to participate in the Medicare or Medicaid programs. The statute requires that we publish, within 60 days of receipt of an organization's complete application, a notice identifying the national accrediting body making the request, describing the nature of the request, and providing at least a 30-day public comment period.

DATES: To be assured consideration, comments must be received at one of the addresses provided below, no later than 5 p.m. on June 25, 2009.

ADDRESSES: In commenting, please refer to file code CMS–2487–PN. 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–2487–PN, 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–2487–PN, 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 information on viewing public comments, see the beginning of the **SUPPLEMENTARY INFORMATION** section.

FOR FURTHER INFORMATION CONTACT:
Cindy Melanson, (410) 786–0310.
Patricia Chmielewski, (410) 786–6899.

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

Under the Medicare program, eligible beneficiaries may receive covered services from an ambulatory surgical center (ASC) provided certain requirements are met. Section 1832(a)(2)(F)(i) of the Social Security Act (the Act) establishes distinct criteria for facilities seeking designation as an ASC. Regulations concerning provider agreements are at 42 CFR part 489 and those pertaining to activities relating to the survey and certification of facilities are at 42 CFR part 488. The regulations at 42 CFR part 416 specify the conditions that an ASC must meet in order to participate in the Medicare program, the scope of covered services, and the conditions for Medicare payment for ASCs.

Generally, in order to enter into a provider agreement with the Medicare program, an ASC must first be certified by a State survey agency as complying with the conditions or requirements set forth in part 416 of our regulations. Thereafter, the ASC is subject to regular surveys by a State survey agency to determine whether it continues to meet these requirements. There is an alternative, however, to surveys by State agencies.

Section 1865(a)(1) of the Act (as redesignated under section 125 of the Medicare Improvements for Patients and Providers Act of 2008 (MIPPA) (Pub. L. 110–275)) provides that, if a provider entity demonstrates through accreditation by an approved national accrediting organization that all applicable Medicare conditions are met or exceeded, we will deem those provider entities as having met the requirements. (We note that section 125 of MIPPA redesignated subsections (b) through (e) of subsection 1865 of the Act as (a) through (d) respectively.) Accreditation by an accrediting organization is voluntary and is not required for Medicare participation.

If an accrediting organization is recognized by the Secretary as having standards for accreditation that meet or exceed Medicare requirements, any provider entity accredited by the national accrediting body's approved program would be deemed to meet the Medicare conditions. A national accrediting organization applying for deeming authority under part 488, subpart A, must provide us with reasonable assurance that the accrediting organization requires the accredited provider entities to meet requirements that are at least as stringent as the Medicare conditions. Our regulations concerning the reapproval of accrediting organizations are set forth at § 488.4 and § 488.8(d)(3). The regulations at § 488.8(d)(3) require accrediting organizations to reapply for continued deeming authority every 6 years or sooner as determined by us.

II. Approval of Deeming Organizations

Section 1865(a)(2) of the Act and our regulations at § 488.8(a) require that our findings concerning review and reapproval of a national accrediting organization's requirements consider, among other factors, the applying accrediting organization's: requirements for accreditation; survey procedures; resources for conducting required surveys; capacity to furnish information for use in enforcement activities; monitoring procedures for provider entities found not in compliance with the conditions or requirements; and ability to provide us with the necessary data for validation.

Section 1865(a)(3)(A) of the Act further requires that we publish, within 60 days of receipt of an organization's complete application, a notice identifying the national accrediting body making the request, describing the nature of the request, and providing at least a 30-day public comment period. We have 210 days from the receipt of a complete application to publish notice of approval or denial of the application.

The purpose of this proposed notice is to inform the public of AOA's request for continued deeming authority for ASCs. This notice also solicits public comment on whether AOA's requirements meet or exceed the Medicare conditions for coverage (CfC) for ASCs.

III. Evaluation of Deeming Authority Request

AOA submitted all the necessary materials to enable us to make a determination concerning its request for reapproval as a deeming organization for ASCs. This application was determined to be complete on April 6, 2009. Under Section 1865(a)(2) of the Act and our regulations at § 488.8 (Federal review of accrediting organizations), our review and evaluation of AOA will be conducted in accordance with, but not necessarily limited to, the following factors:

• The equivalency of AOA's standards for an ASC as compared with CMS' ASC conditions for coverage.

• AOA's survey process to determine the following:

—The composition of the survey team, surveyor qualifications, and the ability of the organization to provide continuing surveyor training.

—The comparability of AOA's processes to those of State agencies, including survey frequency, and the ability to investigate and respond appropriately to complaints against accredited facilities.

—AOA's processes and procedures for monitoring ASCs found out of compliance with AOA's program requirements. These monitoring procedures are used only when AOA identifies noncompliance. If noncompliance is identified through validation reviews, the State survey agency monitors corrections as specified at § 488.7(d).

—AOA's capacity to report deficiencies to the surveyed facilities and respond to the facility's plan of correction in a timely manner.

—AOA's capacity to provide us with electronic data and reports necessary for effective validation and assessment of the organization's survey process.

—The adequacy of AOA's staff and other resources, and its financial viability.

—AOA's capacity to adequately fund required surveys.

—AOA's policies with respect to whether surveys are announced or unannounced, to assure that surveys are unannounced.

—AOA's agreement to provide us with a copy of the most current accreditation survey together with any other information related to the survey as we may require (including corrective action plans).

IV. Collection of Information Requirements

This document does not impose information collection and recordkeeping requirements. Consequently, it need not be reviewed by the Office of Management and Budget under the authority of the Paperwork Reduction Act of 1995 (44 U.S.C. 35).

V. 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; No. 93.773 Medicare—Hospital Insurance Program; and No. 93.774, Medicare—Supplementary Medical Insurance Program)

Dated: April 30, 2009.

Charlene Frizzera,

Acting Administrator, Centers for Medicare & Medicaid Services.

[FR Doc. E9–12109 Filed 5–22–09; 8:45 am]

BILLING CODE 4120–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Cancer Institute; Notice of Closed Meeting

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 meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Cancer Institute Initial Review Group, Subcommittee H—Clinical Groups.

Date: July 20–21, 2009.

Time: 8 a.m. to 8 p.m.

Agenda: To review and evaluate grant applications.

Place: Bethesda Marriott, 5151 Pooks Hill Road, Bethesda, MD 20814.

Contact Person: Timothy C. Meeker, MD, PhD, Scientific Review Officer, Resources and Training Review Branch, Division of Extramural Activities, National Cancer Institute, 6116 Executive Boulevard, Room 8103, Bethesda, MD 20892. (301) 594–1279. *meekert@mail.nih.gov*.

(Catalogue of Federal Domestic Assistance Program Nos. 93.392, Cancer Construction; 93.393, Cancer Cause and Prevention Research; 93.394, Cancer Detection and Diagnosis Research; 93.395, Cancer Treatment Research; 93.396, Cancer Biology Research; 93.397, Cancer Centers Support; 93.398, Cancer Research Manpower; 93.399, Cancer Control, National Institutes of Health, HHS)

Dated: May 18, 2009.

Jennifer Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. E9–12201 Filed 5–22–09; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

Healthcare Infection Control Practices Advisory Committee, (HICPAC)

In accordance with section 10(a) (2) of the Federal Advisory Committee Act (Pub. L. 92–463), the Centers for Disease Control and Prevention (CDC) announces the following meeting for the aforementioned committee:

Times and Dates: 9 a.m.–5 p.m., June 15, 2009. 9 a.m.–12 p.m., June 16, 2009.

Place: CDC, Tom Harkin Global Communications Center (Building 19), Auditorium B3, 1600 Clifton Road, Atlanta, Georgia 30333.

Status: Open to the public, limited only by the space available.

Purpose: The Committee is charged with providing advice and guidance to the Secretary, the Assistant Secretary for Health, the Director, CDC, and the Director, National Center for Preparedness, Detection, and Control of Infectious Diseases (NCPDCID), regarding: (1) The practice of hospital infection control; (2) strategies for surveillance, prevention, and control of infections (*e.g.*, nosocomial infections), antimicrobial resistance, and related events in settings where healthcare is provided; and (3) periodic updating of guidelines and other policy statements regarding prevention of healthcare-associated infections and healthcare-related conditions.

Matters to be Discussed: The agenda will include a follow up discussion of Health and Human Services Healthcare-Associated Infections (HAI) elimination plan, Norovirus Guideline, and Healthcare Personnel Infection Control Guideline.

Agenda items are subject to change as priorities dictate.

Contact Person for More Information: Wendy Vance, Committee Management Specialist, Division of Healthcare Quality Promotion, NCPDCID, CDC, l600 Clifton Road, NE., Mailstop A–07, Atlanta, Georgia 30333 Telephone (404) 639–2891.

The Director, Management Analysis and Services Office, has been delegated the authority to sign **Federal Register** notices pertaining to announcements of meetings and other committee management activities, for both CDC and the Agency for Toxic Substances and Disease Registry.

Dated: May 18, 2009.

Elaine L. Baker,

Director, Management Analysis and Services Office, Centers for Disease Control and Prevention (CDC).

[FR Doc. E9–12119 Filed 5–22–09; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

National Center for Injury Prevention and Control Initial Review Group, (NCIPC IRG)

In accordance with section 10(a)(2) of the Federal Advisory Committee Act (Pub. L. 92–463), the Centers for Disease Control and Prevention (CDC) announce the following teleconference meetings:

Times and Dates:

12:30 p.m.–12:45 p.m., June 22, 2009 (Open).
12:45 p.m.–7 p.m., June 22, 2009 (Closed).
9 a.m.–9:15 a.m., June 23, 2009 (Open).
9:15 a.m.–5 p.m., June 23, 2009 (Closed).
9 a.m.–9:15 a.m., June 24, 2009 (Open).
9:15 a.m.–5 p.m., June 24, 2009 (Closed).
9 a.m.–9:15 a.m., June 25, 2009 (Open).
9:15 a.m.–5 p.m., June 25, 2009 (Closed).

Place: Teleconference, Toll Free: 877–468–4185, Participant Pass Code: 3772769.

Status: Portions of the meeting will be closed to the public in accordance with provisions set forth in Section 552b(c)(4) and (6), Title 5, U.S.C., and the Determination of the Director, Management Analysis and Services Office, CDC, pursuant to Section 10(d) of Public Law 92–463.

Purpose: This group is charged with providing advice and guidance to the Secretary, Department of Health and Human Services, and the Director, CDC, concerning the scientific and technical merit of grant and cooperative agreement applications received from academic institutions and other public and private profit and nonprofit organizations, including State and local government agencies, to conduct specific injury research that focuses on prevention and control.

Matters To Be Discussed: The meetings will include the review, discussion, and evaluation of applications submitted in response to Fiscal Year 2009 Requests for Applications related to the following individual research announcement: RFA–EH–09–001 Climate Change: Environmental Impact on Human Health (U01).

Agenda items are subject to change as priorities dictate.

CONTACT PERSON FOR MORE INFORMATION: Rick Waxweiler, Ph.D., Director, Extramural Research Program Office, National Center for Injury Prevention & Control and Executive Secretary, NCIPC IRG, CDC, 4770 Buford Highway, N.E., M/S F–62, Atlanta, Georgia 30341, Telephone 770–488-4850.

The Director, Management Analysis and Services Office has been delegated the authority to sign **Federal Register** notices pertaining to announcements of meetings and other committee management activities for both CDC and the Agency for Toxic Substances and Disease Registry.

Dated: May 18, 2009.

Elaine L. Baker,

Director, Management Analysis and Services Office, Centers for Disease Control and Prevention.

[FR Doc. E9–12120 Filed 5–22–09; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Agency for Healthcare Research and Quality

Notice of Meeting

In accordance with section 10(d) of the Federal Advisory Committee Act (5 U.S.C., Appendix 2), announcement is made of a Health Care Policy and Research Special Emphasis Panel (SEP) meeting.

A Special Emphasis Panel is a group of experts in fields related to health care research who are invited by the Agency for Healthcare Research and Quality (AHRQ), and agree to be available, to conduct on an as needed basis, scientific reviews of applications for AHRQ support. Individual members of the Panel do not attend regularly-scheduled meetings and do not serve for fixed terms or a long period of time. Rather, they are asked to participate in particular review meetings which require their type of expertise.

Substantial segments of the upcoming SEP meeting listed below will be closed to the public in accordance with the Federal Advisory Committee Act, section 10(d) of 5 U.S.C., Appendix 2 and 5 U.S.C. 552b(c)(6). Grant applications for the Accelerating Development of Methods for the Study of Complex Patients (R21) applications are to be reviewed and discussed at this meeting. These discussions are likely to reveal personal information concerning individuals associated with the applications. This information is exempt from mandatory disclosure under the above-cited statutes.

SEP Meeting on: Accelerating Development of Methods for the Study of Complex Patients (R21).

Date: June 23, 2009 (Open on June 23 from 1 p.m. to 1:15 p.m. and closed for the remainder of the meeting).

Place: Agency for Healthcare Research and Quality, John Eisenberg Building, Conference Center, Rockville, Maryland 20850.

Contact Person: Anyone wishing to obtain a roster of members, agenda or minutes of the nonconfidential portions of this meeting should contact Mrs. Bonnie Campbell, Committee Management Officer, Office of Extramural Research, Education and Priority Populations, AHRQ, 540 Gaither Road, Room 2038, Rockville, Maryland 20850, Telephone (301) 427–1554.

Agenda items for this meeting are subject to change as priorities dictate.

Dated: May 15, 2009.

Carolyn M. Clancy,

Director.

[FR Doc. E9–12068 Filed 5–22–09; 8:45 am]

BILLING CODE 4160–90–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Eunice Kennedy Shriver National Institute of Child Health & Human Development; Notice of Closed Meeting

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 meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The contract proposals and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the contract proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Child Health and Human Development Special Emphasis Panel; Pediatric Functional Neuroimaging Research Network.

Date: June 26, 2009.

Time: 8 a.m. to 4 p.m.

Agenda: To review and evaluate contract proposals

Place: Hyatt Regency Bethesda, One Bethesda Metro Center, 7400 Wisconsin Avenue, Bethesda, MD 20814.

Contact Person: Sathasiva B. Kandasamy, PhD, Scientific Review Administrator, Division of Scientific Review, National Institute of Child Health and Human Development, 6100 Executive Boulevard, Room 5B01, Bethesda, MD 20892–9304, (301) 435–6680, *skandasa@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.864, Population Research; 93.865, Research for Mothers and Children; 93.929, Center for Medical Rehabilitation Research; 93.209, Contraception and Infertility Loan Repayment Program, National Institutes of Health, HHS)

Dated: May 19, 2009.

Jennifer Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. E9–12239 Filed 5–22–09; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Eunice Kennedy Shriver National Institute of Child Health & Human Development; Notice of Closed Meeting

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 meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Child Health and Human Development Initial Review Group, Reproduction, Andrology, and Gynecology Subcommittee.

Date: June 22, 2009.

Time: 8 a.m. to 6 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: Dennis Leszczynski, PhD, Scientific Review Administrator, Division of Scientific Review, National Institute of Child Health and Human Development, NIH, 6100 Executive Boulevard, Room 5B01, Bethesda, MD 20892, (301) 435–2717. *leszczyd@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.864, Population Research; 93.865, Research for Mothers and Children; 93.929, Center for Medical Rehabilitation Research; 93.209, Contraception and Infertility Loan Repayment Program, National Institutes of Health, HHS)

Dated: May 19, 2009.

Jennifer Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. E9–12236 Filed 5–22–09; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Cancer Institute; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of a meeting of the Board of Scientific Counselors for Clinical Sciences and Epidemiology National Cancer Institute.

The meeting will be closed to the public as indicated below in accordance with the provisions set forth in section 552b(c)(6), Title 5 U.S.C., as amended for the review, discussion, and evaluation of individual intramural programs and projects conducted by the National Cancer Institute, including consideration of personnel qualifications and performance, and the competence of individual investigators, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: Board of Scientific Counselors for Clinical Sciences and Epidemiology National Cancer Institute.

Date: July 14, 2009.

Time: 9 a.m. to 4:30 p.m.

Agenda: To review and evaluate personal qualifications and performance, and competence of individual investigators.

Place: National Institutes of Health, National Cancer Institute, 9000 Rockville Pike, Building 31, Conference Room 10, Bethesda, MD 20892.

Contact Person: Brian E. Wojcik, PhD, Senior Review Administrator, Institute Review Office, Office of the Director, National Cancer Institute, 6116 Executive Boulevard, Room 2201, Bethesda, MD 20892, (301) 496–7628, *wojcikb@mail.nih.gov.*

In the interest of security, NIH has instituted stringent procedures for entrance onto the NIH campus. All visitor vehicles, including taxicabs, hotel, and airport shuttles will be inspected before being allowed on campus. Visitors will be asked to show one form of identification (for example, a government-issued photo ID, driver's license, or passport) and to state the purpose of their visit.

Information is also available on the Institute's/Center's home page: *deainfo.nci.nih.gov/advisory/bsc.htm,* where an agenda and any additional information for the meeting will be posted when available.

(Catalogue of Federal Domestic Assistance Program Nos. 93.392, Cancer Construction; 93.393, Cancer Cause and Prevention Research; 93.394, Cancer Detection and Diagnosis Research; 93.395, Cancer Treatment Research; 93.396, Cancer Biology Research; 93.397, Cancer Centers Support; 93.398, Cancer Research Manpower; 93.399, Cancer Control, National Institutes of Health, HHS)

Dated: May 19, 2009.

Jennifer Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. E9–12232 Filed 5–22–09; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Nursing Research; 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 of Nursing Research Special Emphasis Panel. NINR Core Center Grants and Predoctoral Individual National Research Service Awards.

Date: June 19, 2009.

Time: 10 a.m. to 2 p.m.

Agenda: To review and evaluate grant applications.

Place: Bethesda Marriott Suites, 6711 Democracy Boulevard, Bethesda, MD 20817.

Contact Person: Weiqun Li, MD, Scientific Review Administrator, National Institute of Nursing Research, National Institutes of Health, 6701 Democracy Blvd., Ste. 710, Bethesda, MD 20892. (301) 594–5966. *wli@mail.nih.gov.*

Name of Committee: National Institute of Nursing Research Special Emphasis Panel. Research Program Projects Review.

Date: June 24, 2009.

Time: 8 a.m. to 6 p.m.

Agenda: To review and evaluate grant applications.

Place: Bethesda Marriott, 5151 Pooks Hill Road, Bethesda, MD 20814.

Contact Person: Mario Rinaudo, MD, Scientific Review Administrator, Office of Review, National Inst of Nursing Research, National Institutes of Health, 6701 Democracy Blvd (DEM 1), Suite 710, Bethesda, MD 20892. 301–594–5973. *mrinaudo@mail.nih.gov.*

Any interested person may file written comments with the committee by forwarding the statement to the Contact Person listed on this notice. The statement should include the name, address, telephone number and when applicable, the business or professional affiliation of the interested person.

(Catalogue of Federal Domestic Assistance Program Nos. 93.361, Nursing Research, National Institutes of Health, HHS)

Dated: May 19, 2009.

Jennifer Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. E9–12229 Filed 5–22–09; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Eunice Kennedy Shriver National Institute of Child Health & Human Development; Notice of Closed Meeting

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 meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The contract proposals and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the contract proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Child Health and Human Development Special Emphasis Panel, Brain and Tissue Bank Repository.

Date: June 24, 2009.

Time: 1 p.m. to 5 p.m.

Agenda: To review and evaluate contract proposals.

Place: National Institutes of Health, 6100 Executive Boulevard, Room 5B01, Rockville, MD 20852 (Telephone Conference Call).

Contact Person: Sathasiva B. Kandasamy, PhD, Scientific Review Administrator, Division Of Scientific Review, National Institute of Child Health and Human Development, 6100 Executive Boulevard, Room 5B01, Bethesda, MD 20892–9304, (301) 435–6680. *skandasa@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.864, Population Research; 93.865, Research for Mothers and Children; 93.929, Center for Medical Rehabilitation Research; 93.209, Contraception and Infertility Loan Repayment Program, National Institutes of Health, HHS)

Dated: May 19, 2009.

Jennifer Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. E9–12224 Filed 5–22–09; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Eunice Kennedy Shriver National Institute of Child Health & Human Development; Notice of Closed Meeting

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 meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Child Health and Human Development Initial Review Group; Biobehavioral and Behavioral Sciences Subcommittee.

Date: June 23–24, 2009.

Time: 9 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Embassy Suites Washington, DC, 1250 22nd Street, NW., Washington, DC 20037.

Contact Person: Marita R. Hopmann, PhD, Scientific Review Administrator, Division of Scientific Review, National Institute of Child Health, and Human Development, NIH, 6100 Executive Boulevard, Room 5B01, Bethesda, MD 20892, (301) 435–6911, *hopmannm@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.864, Population Research; 93.865, Research for Mothers and Children; 93.929, Center for Medical Rehabilitation Research; 93.209, Contraception and Infertility Loan Repayment Program, National Institutes of Health, HHS)

Dated: May 19, 2009.

Jennifer Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. E9–12223 Filed 5–22–09; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Center for Scientific Review; Amended Notice of Meeting

Notice is hereby given of a change in the meeting of the Center for Scientific Review Special Emphasis Panel, June 1, 2009, 8 a.m. to June 1, 2009, 6 p.m., National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD, 20892 which was published in the **Federal Register** on April 21, 2009, 74 FR 18242–18243.

The starting time of the meeting on June 1, 2009 has been changed to 1:30 p.m. until adjournment. The meeting date and location remains the same. The meeting is closed to the public.

Dated: May 18, 2009.

Jennifer Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. E9–12227 Filed 5–22–09; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Environmental Health Sciences; Notice of Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of a meeting of the Board of Scientific Counselors, NIEHS.

The meeting will be open to the public as indicated below, with attendance limited to space available. Individuals who plan to attend and need special assistance, such as sign language interpretation or other reasonable accommodations, should notify the Contact Person listed below in advance of the meeting.

The meeting will be closed to the public as indicated below in accordance with the provisions set forth in section 552b(c)(6), Title 5 U.S.C., as amended for the review, discussion, and evaluation of individual other conducted by the National Institute of Environmental Health Sciences, including consideration of personnel qualifications and performance, and the competence of individual investigators, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: Board of Scientific Counselors, NIEHS.

Date: June 14–16, 2009.

Closed: June 14, 2009, 7 p.m. to 10 p.m.

Agenda: To review and evaluate programmatic and personnel issues.

Place: Doubletree Guest Suites, 2515 Meridian Parkway, Research Triangle Park, NC 27713.

Closed: June 15, 2009, 8 a.m. to 9 a.m.

Agenda: To review and evaluate programmatic and personnel issues.

Place: Nat. Inst. of Environmental Health Sciences, 111 T. W. Alexander Drive, Executive Conference Room, Research Triangle Park, NC 27709.

Open: June 15, 2009, 9 a.m. to 12:15 p.m.

Agenda: An overview of the organization and research in the Epidemiology Branch.

Place: Nat. Inst. of Environmental Health Sciences, Building 101, Rodbell Auditorium, 111 T. W. Alexander Drive, Conference Rooms 101 A, B, and C, Research Triangle Park, NC 27709.

Closed: June 15, 2009, 12:50 p.m. to 1:35 p.m.

Agenda: To review and evaluate programmatic and personnel issues.

Place: Nat. Inst. of Environmental Health Sciences, 111 T. W. Alexander Drive, Executive Conference Room, Research Triangle Park, NC 27709.

Closed: June 15, 2009, 1:35 p.m. to 4:40 p.m.

Agenda: To review and evaluate programmatic and personnel issues.

Place: Nat. Inst. of Environmental Health Sciences, Building 101, Rodbell Auditorium, 111 T. W. Alexander Drive, Research Triangle Park, NC 27709.

Closed: June 15, 2009, 4:40 p.m. to 5:10 p.m.

Agenda: To review and evaluate programmatic and personnel issues.

Place: Nat. Inst. of Environmental Health Sciences, 111 T. W. Alexander Drive, Executive Conference Room, Research Triangle Park, NC 27709.

Closed: June 15, 2009, 7:30 p.m. to Adjournment.

Agenda: To review and evaluate programmatic and personnel issues.

Place: Doubletree Guest Suites, 2515 Meridian Parkway, Research Triangle Park, NC 27713.

Open: June 16, 2009, 8:30 a.m. to 11:25 a.m.

Agenda: Scientific Presentations.

Place: Nat. Inst. of Environmental Health Sciences, Building 101, Rodbell Auditorium, 111 T. W. Alexander Drive, Conference Rooms 101 A, B, and C, Research Triangle Park, NC 27709.

Closed: June 16, 2009, 11:25 a.m. to 11:55 a.m.

Agenda: To review and evaluate programmatic and personnel issues.

Place: Nat. Inst. of Environmental Health Sciences, 111 T. W. Alexander Drive, Executive Conference Room, Research Triangle Park, NC 27709.

Closed: June 16, 2009, 12:45 p.m. to 2:15 p.m.

Agenda: To review and evaluate programmatic and personnel issues.

Place: Nat. Inst. of Environmental Health Sciences, 111 T. W. Alexander Drive, Executive Conference Room, Research Triangle Park, NC 27709.

Closed: June 16, 2009, 2:15 p.m. to Adjournment.

Agenda: To review and evaluate programmatic and personnel issues.

Place: Nat. Inst. of Environmental Health Sciences, Building 101, Rodbell Auditorium, 111 T. W. Alexander Drive, Conference Rooms 101 A, B, and C, Research Triangle Park, NC 27709.

Contact Person: Perry J Blackshear, PhD, MD, Acting Scientific Director, Division of Intramural Research, National Inst. of Environmental Health Sciences, National Institutes of Health, P.O. Box 12233, Research Triangle Park, NC 27709. (919) 541–4899. *black009@niehs.nih.gov.*

Any interested person may file written comments with the committee by forwarding the statement to the Contact Person listed on this notice. The statement should include the name, address, telephone number and when aplicable, the business or professional affiliation of the interested person.

(Catalogue of Federal Domestic Assistance Program Nos. 93.115, Biometry and Risk Estimation—Health Risks from Environmental Exposures; 93.142, NIEHS Hazardous Waste Worker Health and Safety Training; 93.143, NIEHS Superfund Hazardous Substances—Basic Research and Education; 93.894, Resources and Manpower Development in the Environmental Health Sciences; 93.113, Biological Response to Environmental Health Hazards; 93.114, Applied Toxicological Research and Testing, National Institutes of Health, HHS)

Dated: May 19, 2009.

Jennifer Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. E9–12241 Filed 5–22–09; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Nursing Research; Notice of Closed Meeting

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 meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Nursing Research Initial Review Group.

Date: June 18–19, 2009.

Time: 8 a.m. to 10 a.m.

Agenda: To review and evaluate grant applications.

Place: Bethesda Marriott Suites, 6711 Democracy Boulevard, Bethesda, MD 20817.

Contact Person: Weiqun Li, MD, Scientific Review Officer, National Institute of Nursing Research, National Institutes of Health, 6701 Democracy Blvd., Ste. 710, Bethesda, MD 20892, (301) 594–5966, *wli@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.361, Nursing Research, National Institutes of Health, HHS)

Dated: May 19, 2009.

Jennifer Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. E9–12240 Filed 5–22–09; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Agency for Healthcare Research and Quality

Notice of Meeting

In accordance with section 10(d) of the Federal Advisory Committee Act (5 U.S.C., Appendix 2), announcement is made of a Health Care Policy and Research Special Emphasis Panel (SEP) meeting.

A Special Emphasis Panel is a group of experts in fields related to health care research who are invited by the Agency for Healthcare Research and Quality (AHRQ), and agree to be available, to conduct on an as needed basis, scientific reviews of applications for AHRQ support. Individual members of the Panel do not attend regularly-scheduled meetings and do not serve for fixed terms or a long period of time. Rather, they are asked to participate in particular review meetings which require their type of expertise.

Substantial segments of the upcoming SEP meeting listed below will be closed to the public in accordance with the Federal Advisory Committee Act, section 10(d) of 5 U.S.C., Appendix 2 and 5 U.S.C. 552b(c)(6). Grant applications for the Limited Competition Review RFA HS 08–004 (R18) are to be reviewed and discussed at this meeting. These discussions are likely to reveal personal information concerning individuals associated with the applications. This information is exempt from mandatory disclosure under the above-cited statutes.

SEP Meeting on: Limited Competition Review RFA HS 08–004 (R18)

Date: June 23, 2009 (Open on June 23 from 8 a.m. to 8:15 a.m. and closed for the remainder of the meeting)

Place: Agency for Healthcare Research and Quality, John Eisenberg Building, Conference Center, Rockville, Maryland 20850.

Contact Person: Anyone wishing to obtain a roster of members, agenda or minutes of the non confidential portions of this meeting should contact Mrs. Bonnie Campbell, Committee Management Officer, Office of Extramural Research, Education and Priority Populations, AHRQ, 540 Gaither Road, Room 2038, Rockville, Maryland 20850, Telephone (301) 427–1554.

Agenda items for this meeting are subject to change as priorities dictate.

Dated: May 15, 2009.

Carol M. Clancy,

Director.

[FR Doc. E9–12069 Filed 5–22–09; 8:45 am]

BILLING CODE 4160–90–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Agency for Healthcare Research and Quality

Notice of Meeting

In accordance with section 10(d) of the Federal Advisory Committee Act (5 U.S.C., Appendix 2), announcement is made of a Health Care Policy and Research Special Emphasis Panel (SEP) meeting.

A Special Emphasis Panel is a group of experts in fields related to health care research who are invited by the Agency for Healthcare Research and Quality (AHRQ), and agree to be available, to conduct on an as needed basis, scientific reviews of applications for AHRQ support. Individual members of the Panel do not attend regularly-scheduled meetings and do not serve for fixed terms or a long period of time. Rather, they are asked to participate in particular review meetings which require their type of expertise.

Substantial segments of the upcoming SEP meeting listed below will be closed to the public in accordance with the Federal Advisory Committee Act, section 10(d) of 5 U.S.C., Appendix 2 and 5 U.S.C. 552b(c)(6). Grant applications for the AHRQ Research Infrastructure Program: Phase II Limited Competition (R24) applications are to be reviewed and discussed at this meeting. These discussions are likely to reveal personal information concerning individuals associated with the applications. This information is exempt from mandatory disclosure under the above-cited statutes.

SEP Meeting on: AHRQ Research Infrastructure Program Phase H Limited Competition (R24).

Date: June 9, 2009. (Open on June 9 from 11 a.m. to 11:15 a.m. and closed for the remainder of the meeting.)

Place: Agency for Healthcare Research and Quality, John Eisenberg Building, Conference Center, Rockville, Maryland 20850.

Contact Person: Anyone wishing to obtain a roster of members, agenda or minutes of the non-confidential portions of this meeting should contact Mrs. Bonnie Campbell, Committee Management Officer, Office of Extramural Research, Education and Priority Populations, AHRQ, 540 Gaither Road, Room 2038, Rockville, Maryland 20850, Telephone (301) 427–1554.

Agenda items for this meeting are subject to change as priorities dictate.

Dated: May 15, 2009.

Carol M. Clancy,

Director.

[FR Doc. E9–12067 Filed 5–22–09; 8:45 am]

BILLING CODE 4160–90–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute on Aging; Notice of Closed Meeting

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 meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute on Aging Special Emphasis Panel, ARRA REVISION I.

Date: June 5, 2009.

Time: 2 p.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: Bita Nakhai, PhD, Scientific Review Officer, Scientific Review Branch, National Institute on Aging, Gateway Bldg., 2C212, 7201 Wisconsin Avenue, Bethesda, MD 20814. 301–402–7701. *nakhaib@nia.nih.gov.*

This notice is being published less than 15 days prior to the meeting due to the timing limitations imposed by the review and funding cycle.

(Catalogue of Federal Domestic Assistance Program Nos. 93.866, Aging Research; 93.701, ARRA Related Biomedical Research and Research Support Awards., National Institutes of Health, HHS)

Dated: May 15, 2009.

Jennifer Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. E9–12200 Filed 5–22–09; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

Advisory Committee to the Director, Centers for Disease Control and Prevention (ACD, CDC)

Notice of Cancellation: This notice was published in the **Federal Register** on May 19, 2009, Volume 74, Number 95, pages 23422–23423. The meeting previously scheduled to convene on June 4, 2009, has been cancelled.

Contact Person for More Information: Brad Perkins, M.D., M.B.A., Executive Officer, Advisory Committee to the Director, CDC, 1600 Clifton Road, NE., M/S D–14, Atlanta, Georgia 30333. Telephone 404/639–7000.

The Director, Management Analysis and Services Office, has been delegated the authority to sign **Federal Register** notices pertaining to announcements of meetings and other committee management activities, for both CDC and the Agency for Toxic Substances and Disease Registry.

Dated: May 19, 2009.

Elaine L. Baker,

Director, Management Analysis and Services Office, Centers for Disease Control and Prevention.

[FR Doc. E9–12123 Filed 5–22–09; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HOMELAND SECURITY

Office of the Secretary

Public Workshop: Privacy Compliance Fundamentals—PTAs, PIAs, and SORNs

AGENCY: Privacy Office, DHS.

ACTION: Notice announcing public workshop.

SUMMARY: The Department of Homeland Security Privacy Office will host a public workshop, ''Privacy Compliance Fundamentals—PTAs, PIAs, and SORNs.''

DATES: The workshop will be held on June 10, 2009, from 9 a.m. to 4:30 p.m.

ADDRESSES: The workshop will be held in the auditorium at the DHS Offices at the GSA Regional Headquarters Building located at 7th and D Streets, SW., Washington, DC, 20024.

FOR FURTHER INFORMATION CONTACT: Tamara Baker, Privacy Office, Department of Homeland Security, Washington, DC 20528; by telephone 703–235–0780; by facsimile 703–235–

0442; or by e-mail at *privacyworkshop@dhs.gov*.

SUPPLEMENTARY INFORMATION: The Department of Homeland Security (DHS) Privacy Office is holding a public workshop that will provide in-depth training on the privacy compliance process at DHS, and specifically how to write privacy impact assessments (PIAs) and systems of records notices (SORNs). A case study will be used to illustrate a step-by-step approach to researching, preparing, and writing these documents. The workshop will highlight Official Guidance for the Privacy Impact Assessments and Systems of Records Notices.

The workshop is open to the public and there is no fee for attendance. *Registration and Security:* In order to facilitate security requirements of the GSA facility, attendees must register in advance for this workshop. Registration closes at 9 a.m., Monday, June 8, 2009. To register, please send an e-mail to *privacyworkshop@dhs.gov*, with the name of the workshop (''Privacy Compliance Fundamentals—PTAs, PIAs, and SORNs'') in the subject line, and your full name and organizational affiliation in the body of the e-mail. Alternatively, you may call 703–235–0780 to register and to provide the Privacy Office with your full name and organizational affiliation.

All attendees who are employed by a federal agency will be required to show their federal agency employee photo identification badge to enter the building. Attendees who do not possess a federal agency employee photo identification badge will need to show a form of government-issued photo identification, such as a driver's license, in order to verify their previously provided registration information. This is a security requirement of the facility.

The Privacy Office will only use your name for the security purposes of this specific workshop and to contact you in the event of a change to the workshop.

Special Assistance: Persons with disabilities who require special assistance should indicate this in their admittance request and are encouraged to identify anticipated special needs as early as possible.

Mary Ellen Callahan,

Chief Privacy Officer, Department of Homeland Security.

[FR Doc. E9–12189 Filed 5–22–09; 8:45 am]

BILLING CODE 9110–9L–P

DEPARTMENT OF HOMELAND SECURITY

U.S. Citizenship and Immigration Services

Agency Information Collection Activities: Form I–90, Revision of a Currently Approved Information Collection; Comment Request

ACTION: 30-Day notice of information collection under review: Form I–90, Application To Replace Permanent Resident Card; OMB Control No.: 1615–0082.

The Department of Homeland Security, U.S. Citizenship and Immigration Services (USCIS) has submitted the following information collection request to the Office of Management and Budget (OMB) for review and clearance in accordance with the Paperwork Reduction Act of 1995. The information collection was previously published in the **Federal Register** on January 26, 2009, at 74 FR 4446, allowing for a 60-day public comment period. USCIS did not receive any comments.

The purpose of this notice is to allow an additional 30 days for public comments. Comments are encouraged and will be accepted until June 25, 2009. This process is conducted in accordance with 5 CFR 1320.10.

Written comments and/or suggestions regarding the item(s) contained in this notice, especially regarding the estimated public burden and associated response time, should be directed to the Department of Homeland Security (DHS), and to the Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), USCIS Desk Officer. Comments may be submitted to: USCIS, Chief, Regulatory Products Division, Clearance Office, 111 Massachusetts Avenue, NW., Washington, DC 20529–2210. Comments may also be submitted to DHS via facsimile to 202–272–8352 or via e-mail at *rfs.regs@dhs.gov*, and to the OMB USCIS Desk Officer via facsimile at 202–395–6974 or via e-mail at *oira_submission@omb.eop.gov*.

When submitting comments by e-mail please make sure to add OMB Control Number 1615–0082 in the subject box. Written comments and suggestions from the public and affected agencies should address one or more of the following four points:

(1) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

(2) Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

(3) Enhance the quality, utility, and clarity of the information to be collected; and

(4) Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

Overview of This Information Collection

(1) *Type of Information Collection:* Revision to an existing information collection.

(2) *Title of the Form/Collection:* Application to Replace Permanent Resident Card.

(3) *Agency form number, if any, and the applicable component of the Department of Homeland Security sponsoring the collection:* Form I–90. U.S. Citizenship and Immigration Services.

(4) *Affected public who will be asked or required to respond, as well as brief abstract: Primary:* Individuals or households. This form will be used by USCIS to determine eligibility to replace a Lawful Permanent Resident Card.

(5) *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond*: 410,799 responses at 55 (.916) minutes per response.

(6) *An estimate of the total public burden (in hours) associated with the collection:* 376,292 annual burden hours.

If you need a copy of the information collection instrument, please visit the Web site at: *http://www.regulations.gov/fdmspublic/component/main*.

We may also be contacted at: USCIS, Regulatory Products Division, 111 Massachusetts Avenue, NW., Washington, DC 20529–2210, telephone number 202–272–8377.

Dated: May 20, 2009.

Stephen Tarragon,

Deputy Chief, Regulatory Products Division, U.S. Citizenship and Immigration Services, Department of Homeland Security.

[FR Doc. E9–12121 Filed 5–22–09; 8:45 am]

BILLING CODE 9111–97–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–1829–DR; Docket ID FEMA–2008–0018]

North Dakota; Amendment No. 5 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of North Dakota (FEMA–1829–DR), dated March 24, 2009, and related determinations.

DATES: *Effective Date:* May 15, 2009.

FOR FURTHER INFORMATION CONTACT: Peggy Miller, Disaster Assistance Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–3886.

SUPPLEMENTARY INFORMATION: The notice of a major disaster declaration for the State of North Dakota is hereby amended to include the following areas among those areas determined to have been adversely affected by the event declared a major disaster by the President in his declaration of March 24, 2009.

Benson, Cavalier, Eddy, McLean, Pembina, Rolette, and Wells Counties for Individual Assistance (already designated for Public Assistance).

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Nancy Ward,

Acting Administrator, Federal Emergency Management Agency.

[FR Doc. E9–12166 Filed 5–22–09; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Docket ID FEMA–2008–0018; Internal Agency Docket No. FEMA–1823–DR]

Oklahoma; Amendment No. 2 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of Oklahoma (FEMA–1823–DR), dated February 17, 2009, and related determinations.

DATES: *Effective Date:* May 18, 2009.

FOR FURTHER INFORMATION CONTACT: Peggy Miller, Disaster Assistance Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–3886.

SUPPLEMENTARY INFORMATION: The Federal Emergency Management Agency (FEMA) hereby gives notice that pursuant to the authority vested in the Administrator, under Executive Order 12148, as amended, Kenneth R. Tingman of FEMA is appointed to act as the Federal Coordinating Officer for this disaster.

This action terminates the appointment of Douglas G. Mayne as Federal Coordinating Officer for this disaster.

(The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households in Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.)

W. Craig Fugate,

Administrator, Federal Emergency Management Agency.

[FR Doc. E9–12177 Filed 5–22–09; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–1829–DR; Docket ID FEMA–2008–0018]

North Dakota; Amendment No. 4 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of North Dakota (FEMA–1829–DR), dated March 24, 2009, and related determinations.

DATES: *Effective Date:* May 13, 2009.

FOR FURTHER INFORMATION CONTACT: Peggy Miller, Disaster Assistance Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–3886.

SUPPLEMENTARY INFORMATION: The notice of a major disaster declaration for the State of North Dakota is hereby amended to include the following areas among those areas determined to have been adversely affected by the event declared a major disaster by the President in his declaration of March 24, 2009.

The Turtle Mountain Band of Chippewa Indian Reservation for Individual Assistance and Public Assistance.

Ramsey County for Individual Assistance (already designated for Public Assistance).

Rolette and Sheridan Counties for Public Assistance.

Billings County for Public Assistance [Categories A and C–G] (already designated for Individual Assistance and emergency protective measures [Category B], including direct Federal assistance, under the Public Assistance program).

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households in Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050 Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance

(Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Nancy Ward,

Acting Administrator, Federal Emergency Management Agency.

[FR Doc. E9–12174 Filed 5–22–09; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Docket ID FEMA–2008–0018; Internal Agency Docket No. FEMA–1831–DR]

Florida; Amendment No. 5 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of Florida (FEMA–1831–DR), dated April 21, 2009, and related determinations.

DATES: *Effective Date:* May 11, 2009.

FOR FURTHER INFORMATION CONTACT: Peggy Miller, Disaster Assistance Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–3886.

SUPPLEMENTARY INFORMATION: The notice of a major disaster declaration for the State of Florida is hereby amended to include the following areas among those areas determined to have been adversely affected by the event declared a major disaster by the President in his declaration of April 21, 2009.

Leon and Wakulla Counties for Individual Assistance (already designated for Public Assistance).

Levy County for Individual Assistance.

Dixie, Gilchrist, Lafayette, and Suwannee Counties for Public Assistance (already designated for Individual Assistance).

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households in Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050 Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Nancy Ward,

Acting Administrator, Federal Emergency Management Agency.

[FR Doc. E9–12173 Filed 5–22–09; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–1836–DR; Docket ID FEMA–2008–0018]

Alabama; Major Disaster and Related Determinations

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This is a notice of the Presidential declaration of a major disaster for the State of Alabama (FEMA–1836–DR), dated May 8, 2009, and related determinations.

DATES: *Effective Date:* May 8, 2009.

FOR FURTHER INFORMATION CONTACT: Peggy Miller, Disaster Assistance Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–3886.

SUPPLEMENTARY INFORMATION: Notice is hereby given that, in a letter dated May 8, 2009, the President issued a major disaster declaration under the authority of the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121–5207 (the Stafford Act), as follows:

I have determined that the damage in certain areas of the State of Alabama resulting from severe storms, flooding, tornadoes, and straight-line winds during the period of April 10–13, 2009, is of sufficient severity and magnitude to warrant a major disaster declaration under the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121–5207 (the ''Stafford Act''). Therefore, I declare that such a major disaster exists in the State of Alabama.

In order to provide Federal assistance, you are hereby authorized to allocate from funds available for these purposes such amounts as you find necessary for Federal disaster assistance and administrative expenses.

You are authorized to provide Public Assistance in the designated areas, Hazard Mitigation throughout the State, and any other forms of assistance under the Stafford Act that you deem appropriate. Consistent with the requirement that Federal assistance is supplemental, any Federal funds provided under the Stafford Act for Public Assistance and Hazard Mitigation will be limited to 75 percent of the total eligible costs. If Other Needs Assistance under Section 408 of the Stafford Act is later warranted, Federal funding under that program will also be limited to 75 percent of the total eligible costs.

Further, you are authorized to make changes to this declaration to the extent allowable under the Stafford Act.

The Federal Emergency Management Agency (FEMA) hereby gives notice that Albert Lewis, of FEMA is appointed to act as the Federal Coordinating Officer for this major disaster.

The following areas of the State of Alabama have been designated as adversely affected by this major disaster:

Cullman, DeKalb, Jackson, Jefferson, and Marshall Counties for Public Assistance.

All counties within the State of Alabama are eligible to apply for assistance under the Hazard Mitigation Grant Program.

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households in Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Nancy Ward,

Acting Administrator, Federal Emergency Management Agency.

[FR Doc. E9–12164 Filed 5–22–09; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Docket ID FEMA–2008–0018; Internal Agency Docket No. FEMA–1839–DR]

Tennessee; Major Disaster and Related Determinations

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This is a notice of the Presidential declaration of a major disaster for the State of Tennessee (FEMA–1839–DR), dated May 15, 2009, and related determinations.

DATES: *Effective Date:* May 15, 2009.

FOR FURTHER INFORMATION CONTACT: Peggy Miller, Disaster Assistance

Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–3886.

SUPPLEMENTARY INFORMATION: Notice is hereby given that, in a letter dated May 15, 2009, the President issued a major disaster declaration under the authority of the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121–5207 (the Stafford Act), as follows:

I have determined that the damage in certain areas of the State of Tennessee resulting from severe storms, tornadoes, and flooding on April 10, 2009, is of sufficient severity and magnitude to warrant a major disaster declaration under the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121–5207 (the ''Stafford Act''). Therefore, I declare that such a major disaster exists in the State of Tennessee.

In order to provide Federal assistance, you are hereby authorized to allocate from funds available for these purposes such amounts as you find necessary for Federal disaster assistance and administrative expenses.

You are authorized to provide Public Assistance in the designated areas, Hazard Mitigation throughout the State, and any other forms of assistance under the Stafford Act that you deem appropriate. Consistent with the requirement that Federal assistance is supplemental, any Federal funds provided under the Stafford Act for Public Assistance and Hazard Mitigation will be limited to 75 percent of the total eligible costs. If Other Needs Assistance under Section 408 of the Stafford Act is later requested and warranted, Federal funding under that program will also be limited to 75 percent of the total eligible costs.

Further, you are authorized to make changes to this declaration to the extent allowable under the Stafford Act.

The Federal Emergency Management Agency (FEMA) hereby gives notice that Terry L. Quarles of FEMA is appointed to act as the Federal Coordinating Officer for this major disaster.

The following areas of the State of Tennessee have been designated as adversely affected by this major disaster:

Benton, McMinn, Rutherford, and Sequatchie Counties for Public Assistance.

All counties within the State of Tennessee are eligible to apply for assistance under the Hazard Mitigation Grant Program.

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households in Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Nancy Ward,

Acting Administrator, Federal Emergency Management Agency.

[FR Doc. E9–12160 Filed 5–22–09; 8:45 am]

BILLING CODE 9110–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–1838–DR; Docket ID FEMA–2008–0018]

West Virginia; Major Disaster and Related Determinations

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This is a notice of the Presidential declaration of a major disaster for the State of West Virginia (FEMA–1838–DR), dated May 15, 2009, and related determinations.

DATES: *Effective Date:* May 15, 2009.

FOR FURTHER INFORMATION CONTACT: Peggy Miller, Disaster Assistance Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–3886.

SUPPLEMENTARY INFORMATION: Notice is hereby given that, in a letter dated May 15, 2009, the President issued a major disaster declaration under the authority of the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121–5207 (the Stafford Act), as follows:

I have determined that the damage in certain areas of the State of West Virginia resulting from severe storms, flooding, mudslides, and landslides beginning on May 3, 2009, and continuing, is of sufficient severity and magnitude to warrant a major disaster declaration under the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121–5207 (the ''Stafford Act''). Therefore, I declare that such a major disaster exists in the State of West Virginia.

In order to provide Federal assistance, you are hereby authorized to allocate from funds available for these purposes such amounts as you find necessary for Federal disaster assistance and administrative expenses.

You are authorized to provide Individual Assistance and Public Assistance in the designated areas and Hazard Mitigation throughout the State. Consistent with the requirement that Federal assistance is supplemental, any Federal funds provided under the Stafford Act for Public Assistance, Hazard Mitigation, and Other Needs Assistance will be limited to 75 percent of the total eligible costs.

Further, you are authorized to make changes to this declaration to the extent allowable under the Stafford Act.

The time period prescribed for the implementation of section 310(a), Priority to Certain Applications for Public Facility and Public Housing Assistance, 42 U.S.C. 5153, shall be for a period not to exceed six months after the date of this declaration.

The Federal Emergency Management Agency (FEMA) hereby gives notice that Edward H. Smith, of FEMA is appointed to act as the Federal Coordinating Officer for this major disaster.

The following areas of the State of West Virginia have been designated as adversely affected by this major disaster:

Mingo and Wyoming Counties for Individual Assistance and Public Assistance.

All counties within the State of West Virginia are eligible to apply for assistance under the Hazard Mitigation Grant Program.

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households in Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Nancy Ward,

Acting Administrator, Federal Emergency Management Agency.

[FR Doc. E9–12161 Filed 5–22–09; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Docket ID FEMA–2008–0018; Internal Agency Docket No. FEMA–1820–DR]

Oklahoma; Amendment No. 2 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of Oklahoma (FEMA–1820–DR),

dated February 15, 2009, and related determinations.

DATES: *Effective Date:* May 18, 2009.

FOR FURTHER INFORMATION CONTACT: Peggy Miller, Disaster Assistance Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–3886.

SUPPLEMENTARY INFORMATION: The Federal Emergency Management Agency (FEMA) hereby gives notice that pursuant to the authority vested in the Administrator, under Executive Order 12148, as amended, Kenneth R. Tingman of FEMA is appointed to act as the Federal Coordinating Officer for this disaster.

This action terminates the appointment of Douglas G. Mayne as Federal Coordinating Officer for this disaster.

The following Catalog of Federal Domestic Assistance (CFDA) Numbers are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households in Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

W. Craig Fugate,

Administrator, Federal Emergency Management Agency.

[FR Doc. E9–12162 Filed 5–22–09; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–1832–DR; Docket ID FEMA–2008–0018]

Indiana; Amendment No. 1 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of Indiana (FEMA–1832–DR), dated April 22, 2009, and related determinations.

DATES: Effective Date: May 13, 2009.

FOR FURTHER INFORMATION CONTACT: Peggy Miller, Disaster Assistance Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–3886.

SUPPLEMENTARY INFORMATION: The notice of a major disaster declaration for the State of Indiana is hereby amended to include the following areas among those areas determined to have been adversely affected by the event declared a major disaster by the President in his declaration of April 22, 2009.

Daviess, Lawrence, and St. Joseph Counties for Individual Assistance.

(The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households in Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050 Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.)

Nancy Ward,

Acting Administrator, Federal Emergency Management Agency.

[FR Doc. E9–12158 Filed 5–22–09; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Docket ID FEMA–2008–0018; Internal Agency Docket No. FEMA–1837–DR]

Mississippi; Major Disaster and Related Determinations

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This is a notice of the Presidential declaration of a major disaster for the State of Mississippi (FEMA–1837–DR), dated May 12, 2009, and related determinations.

DATES: *Effective Date:* May 12, 2009.

FOR FURTHER INFORMATION CONTACT: Peggy Miller, Disaster Assistance Directorate, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–3886.

SUPPLEMENTARY INFORMATION: Notice is hereby given that, in a letter dated May 12, 2009, the President issued a major disaster declaration under the authority of the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121–5207 (the Stafford Act), as follows:

I have determined that the damage in certain areas of the State of Mississippi resulting from severe storms, flooding, and tornadoes during the period of March 25–28, 2009, is of sufficient severity and magnitude to warrant a major disaster declaration under the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121–5207 (''the Stafford Act''). Therefore, I declare that such a major disaster exists in the State of Mississippi.

In order to provide Federal assistance, you are hereby authorized to allocate from funds available for these purposes such amounts as you find necessary for Federal disaster assistance and administrative expenses.

You are authorized to provide Public Assistance in the designated areas, Hazard Mitigation throughout the State, and any other forms of assistance under the Stafford Act that you deem appropriate. Consistent with the requirement that Federal assistance is supplemental, any Federal funds provided under the Stafford Act for Public Assistance and Hazard Mitigation will be limited to 75 percent of the total eligible costs. If Other Needs Assistance under Section 408 of the Stafford Act is later requested and warranted, Federal funding under that program will also be limited to 75 percent of the total eligible costs.

Further, you are authorized to make changes to this declaration to the extent allowable under the Stafford Act.

The Federal Emergency Management Agency (FEMA) hereby gives notice that Donald L. Keldsen, of FEMA, is appointed to act as the Federal Coordinating Officer for this major disaster.

The following areas of the State of Mississippi have been designated as adversely affected by this major disaster:

Amite, Greene, Jackson, Lawrence, Lincoln, Simpson, Stone, Walthall, Wayne, and Wilkinson Counties for Public Assistance.

All counties within the State of Mississippi are eligible to apply for assistance under the Hazard Mitigation Grant Program.

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households in Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance

(Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Nancy Ward,

Acting Administrator, Federal Emergency Management Agency.

[FR Doc. E9–12176 Filed 5–22–09; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

U.S. Customs and Border Protection

[Docket No. USCBP–2009–0014]

Notice of Meeting of the U.S. Customs and Border Protection Airport and Seaport Inspections User Fee Advisory Committee

AGENCY: U.S. Customs and Border Protection, Department of Homeland Security (DHS).

ACTION: Notice of Federal Advisory Committee meeting.

SUMMARY: The U.S. Customs and Border Protection (CBP) Airport and Seaport Inspections User Fee Advisory Committee (Advisory Committee) will meet in open session. The meeting will be open to the public.

DATES: Wednesday, June 10, 2009, from 12 p.m. to 4 p.m. Please note that the meeting may close early if the committee has completed all business.

ADDRESSES: The meeting will be held at Continental Room C, Ronald Reagan Building, 1300 Pennsylvania Ave, NW., Washington, DC. Written material, comments, requests to make oral presentations, and requests to have a copy of your material distributed to each member of the committee prior to the meeting must be submitted to the contact person listed below by Friday, May 29, 2009. Comments must be identified by USCBP–2009–0014 and may be submitted by *one* of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *E-mail: anna.brown@dhs.gov.* Include the docket number in the subject line of the message.
- *Facsimile:* (202) 344–1818.
- *Mail:* Mrs. Jean Brown, Office of Finance, U.S. Customs and Border Protection, 1300 Pennsylvania Avenue, NW., Suite 4.5A, Washington, DC 20229.

Instructions: All submissions received must include the words ''Department of Homeland Security'' and the docket number for this action. Comments received will be posted without alteration at *http://www.regulations.gov,* including any personal information provided.

Docket: For access to the docket to read background documents or comments received by the Airport and Seaport Inspections User Fee Advisory Committee, go to *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Mrs. Jean Brown, Office of Finance, U.S. Customs and Border Protection, 1300 Pennsylvania Ave, NW., Suite 4.5A, Washington, DC 20229; e-mail: *anna.brown@dhs.gov*; telephone: (202) 344–1910; facsimile: (202) 344–1818.

SUPPLEMENTARY INFORMATION: Pursuant to the Federal Advisory Committee Act (5 U.S.C., App.), the Department of Homeland Security (DHS) hereby announces the meeting of the U.S. Customs and Border Protection (CBP) Airport and Seaport Inspections User Fee Advisory Committee (hereinafter, ''Advisory Committee''). This Advisory Committee was established pursuant to section 286(k) of the Immigration and Nationality Act (INA), codified at title 8 U.S.C. 1356(k), which references the Federal Advisory Committee Act (5 U.S.C., App. *et seq.*). With the merger of the Immigration and Naturalization Service into DHS, the Advisory Committee's responsibilities were transferred from the Attorney General to the Commissioner of CBP pursuant to section 1512(d) of the Homeland Security Act of 2002. The Advisory Committee held its first meeting under the direction of CBP on October 22, 2003 (see 68 FR 56301, September 30, 2003). Among other things, the Advisory Committee advises DHS via the Commissioner of CBP on issues related to the performance of airport and seaport inspections involving agriculture, customs, or immigration based concerns. This advice includes, but is not limited to issues such as the time period during which such services should be performed and the proper number and deployment of inspection officers. Additionally, this advice includes the level and the appropriateness of the following fees assessed for CBP services: the immigration user fee pursuant to 8 U.S.C. 1356(d), the customs inspection user fee pursuant to 19 U.S.C. 58c(a)(5), and the agriculture inspection user fee pursuant to 21 U.S.C 136a.

The seventh meeting of the Advisory Committee will be held at the date, time and location specified above. A tentative agenda for the meeting is set forth below.

Tentative Agenda

1. Introduction of Committee members and CBP Personnel.
2. Report of activities since last meeting held on March 5, 2008.
3. Update on the proposal to consolidate customs and immigration user fees.
4. Discussion of Model Ports next steps.
5. Discussion of the ESTA requirement compliance and possible date for enforcement.
6. Overview and discussion of CBP's FY10 budget.
7. Discussion of the impact of the decline in international air passengers on user fee collections and CBP staffing levels.
8. Discussion of the Global Entry implementation, public outreach, and additional foreign partners.
9. Agree on consensus recommendations on the issues discussed.
10. Discussion of Committee administrative issues and scheduling of next meeting.
11. Adjourn.

Procedural

This meeting is open to the public. Please note that the meeting may close early if all business is finished. Public participation in the deliberations is welcome; however, please note that matters outside of the scope of this committee will not be discussed.

All visitors to the Ronald Reagan Building will have to show a picture ID in order to be admitted into the building. Since seating is limited, all persons attending this event must provide notice, preferably by close of business on Friday, May 29, 2009, to Mrs. Jean Brown, Office of Finance, U.S. Customs and Border Protection, 1300 Pennsylvania Avenue, NW., Suite 4.5A, Washington, DC 20229; e-mail: *anna.brown@dhs.gov*; telephone: (202) 344–1910; facsimile: (202) 344–1818.

Information on Services for Individuals With Disabilities

For information on facilities or services for individuals with disabilities or to request special assistance at the meeting, contact Mrs. Jean Brown as soon as possible.

Dated: May 18, 2009.

Elaine Killoran,

Acting Assistant Commissioner, Office of Finance, U.S. Customs and Border Protection.

[FR Doc. E9–12053 Filed 5–22–09; 8:45 am]

BILLING CODE 9111–14–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

[Docket No. USCG–2009–0193]

Lower Mississippi River Waterway Safety Advisory Committee

AGENCY: Coast Guard, DHS.

ACTION: Notice of meeting.

SUMMARY: The Lower Mississippi River Waterway Safety Advisory Committee will meet in New Orleans to discuss various issues relating to navigational safety on the Lower Mississippi River and related waterways. This meeting will be open to the public.

DATES: The Committee will meet on Tuesday, June 2nd, 2009 from 9 a.m. to 12 p.m. This meeting may close early if all business is finished. Written material and requests to make oral presentations should reach the Coast Guard on or before May 28, 2009. Requests to have a copy of your material distributed to each member of the committee should reach the Coast Guard on or before May 28, 2009.

ADDRESSES: The Committee will meet at the New Orleans Yacht Club, 403 North Roadway, West End, New Orleans, LA 70124. Send written material and requests to make oral presentations to Sector Commander, Designated Federal Officer (DFO) of Lower Mississippi River Waterway Safety Advisory Committee, USCG Sector New Orleans, ATTN: Waterways Management, 1615 Poydras St., New Orleans, LA 70112.

FOR FURTHER INFORMATION CONTACT: CWO3 David Chapman, Assistant to DFO of Lower Mississippi River Waterway Safety Advisory Committee, telephone 504–565–5103.

SUPPLEMENTARY INFORMATION: Notice of this meeting is given under the Federal Advisory Committee Act, 5 U.S.C. App. (Pub. L. 92–463).

Agenda of Meeting

The agenda for the June 2, 2009 Committee meeting is as follows:

(1) Introduction of committee members.

(2) Opening Remarks.

(3) Approval of the February 5, 2009 minutes.

(4) Old Business.

(a) Captain of the Port status report.

(b) VTS update report.

(c) Subcommittee/Working Groups update reports.

(5) New Business

(6) Adjournment

Procedural

This meeting is open to the public. Please note that the meeting may close early if all business is finished. At the Chair's discretion, members of the public may make oral presentations during the meeting. If you would like to make an oral presentation at a meeting, please notify the DFO no later than May 28, 2009. Written material for distribution at a meeting should reach the Coast Guard no later than May 28, 2009. If you would like a copy of your material distributed to each member of the committee in advance of a meeting, please submit 25 copies to the DFO no later than May 28, 2009.

Information on Services for Individuals With Disabilities

For information on facilities or services for individuals with disabilities or to request special assistance at the meeting, contact the DFO as soon as possible.

Dated: April 29, 2009.

J.R. Whitehead,

Rear Admiral, U.S. Coast Guard, Commander, 8th Coast Guard District.

[FR Doc. E9–12163 Filed 5–22–09; 8:45 am]

BILLING CODE 4910–15–P

DEPARTMENT OF THE INTERIOR

[LLCAD00000 L19900000.AL 0000]

Meeting of the California Desert Advisory Council

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of public meeting.

SUMMARY: Notice is hereby given, in accordance with Public Laws 92–463 and 94–579, that the California Desert District Advisory Council to the Bureau of Land Management, U.S. Department of the Interior, will participate in a field tour of BLM-administered public lands on Friday, June 19, 2009 from 8 a.m. to 4 p.m., and meet in formal session on Saturday, June 20 from 8 a.m. to 4 p.m., at the Hampton Inn & Suites, 2710 Lenwood Road, Barstow, CA 92311.

The Council and interested members of the public will depart for the field tour at 8:30 a.m. from the lobby of the Hampton Inn & Suites. Members of the public are welcome to participate in the tour but should plan on providing their own transportation, lunch, and beverage.

Agenda topics for the formal session will include updates by Council members and reports from the BLM District Manager and five field office managers. Additional agenda topics are being developed. Once finalized, the meeting agenda will be posted on the BLM California State Web site at *http://www.blm.gov/ca/news/rac.html*.

SUPPLEMENTARY INFORMATION: All Desert District Advisory Council meetings are open to the public. Public comment for items not on the agenda will be scheduled at the beginning of the meeting Saturday morning. Time for public comment may be made available by the Council Chairman during the presentation of various agenda items, and is scheduled at the end of the meeting for topics not on the agenda.

While the Saturday meeting is tentatively scheduled from 8 a.m. to 4 p.m., the meeting could conclude prior to 4 p.m. should the Council conclude its presentations and discussions. Therefore, members of the public interested in a particular agenda item or discussion should schedule their arrival accordingly.

Written comments may be filed in advance of the meeting for the California Desert District Advisory Council, c/o Bureau of Land Management, External Affairs, 22835 Calle San Juan de Los Lagos, Moreno Valley, California 92553. Written comments also are accepted at the time of the meeting and, if copies are provided to the recorder, will be incorporated into the minutes.

FOR FURTHER INFORMATION CONTACT: David Briery, BLM California Desert District External Affairs, (951) 697–5220.

May 15, 2009.

Steven J. Borchard,

District Manager.

[FR Doc. E9–12118 Filed 5–22–09; 8:45 am]

BILLING CODE P

DEPARTMENT OF THE INTERIOR

National Park Service

60-Day Notice of Intention To Request Clearance of Collection of Information; Opportunity for Public Comment

AGENCY: Department of the Interior, National Park Service.

ACTION: Notice and request for comments.

SUMMARY: Under the provisions of the Paperwork Reduction Act of 1995 and 5 CFR Part 1320, Reporting and Record Keeping Requirements, the National Park Service (NPS) invites public comments on an extension of a currently approved information collection (OMB #1024–0064).

DATES: Public comments on this Information Collection Request (ICR) will be accepted on or before July 27, 2009.

ADDRESSES: Send comments to: Edward O. Kassman, Jr., Regulatory Specialist, Planning, Evaluation & Permits Branch, Geologic Resources Division, National Park Service, P.O. Box 25287, Lakewood, Colorado 80225; or via fax at (303) 987–6792; or via e-mail at *Edward_Kassman@nps.gov.* The information collection may be viewed on-line at: *http://www2.nature.nps.gov/geology/mining/9a_text.htm* and *http://www2.nature.nps.gov/geology/oil_and_gas/9b_text.htm.* All responses to the Notice will be summarized and included in the request for the Office of Management and Budget (OMB) approval. All comments will become a matter of public record.

To Request a Draft of Proposed Collection of Information Contact: Edward O. Kassman, Jr., Regulatory Specialist, Planning, Evaluation & Permits Branch, Geologic Resources Division, National Park Service, P.O. Box 25287, Lakewood, Colorado 80225; (303) 969–2146, fax (303) 987–6792, or via e-mail at *Edward_Kassman@nps.gov.* You are entitled to a copy of the entire ICR package free of charge.

SUPPLEMENTARY INFORMATION:

Title: NPS/Minerals Management Program/Mining Claims and Non-Federal Oil and Gas Rights—36 CFR Part 9, Subpart A and Subpart B, respectively.

Form(s): None

OMB Control Number: 1024–0064.

Expiration Date: 02/28/2010

Type of Request: Extension of a currently approved collection of information

Description of Need: The NPS regulates mineral development activities inside park boundaries on mining claims and on non-Federal oil and gas rights under regulations codified at 36 CFR Part 9, Subpart A (''9A regulations''), and 36 CFR Part 9, Subpart B (''9B Regulations''), respectively. The NPS promulgated both sets of regulations in the late 1970s. In the case of mining claims, the NPS promulgated the 9A regulations pursuant to congressional authority granted under the Mining in the Parks Act of 1976, 16 U.S.C. 1901 *et seq.,* and individual park enabling statutes. For non-Federal oil and gas rights, the NPS regulates development activities pursuant to authority under the NPS Organic Act of 1916, 16 U.S.C. 1 *et seq.,* and individual enabling statutes. As directed by Congress, the NPS developed the regulations in order to protect park resources and visitor values from the adverse impacts associated with mineral development in park boundaries. The regulations require operators to submit specific technical information describing their future development plans including steps to mitigate the impacts of operations. NPS uses the information to evaluate proposed operations, ensure that all necessary mitigation measures are employed to protect park resources and values, and ensure compliance with all applicable laws and regulations.

Description of respondents: One-fourth medium to large publicly owned companies and three-fourth private entities.

Estimated average number of respondents: 24 per year.

Estimated average number of responses: 24 per year.

Frequency of Response: 1 per respondent.

Estimated average time burden per respondent: 176 hours.

Estimated total annual reporting burden: 4,224 hours.

Comments are invited on: (1) The practical utility of the information being gathered; (2) the accuracy of the burden hour estimate; (3) ways to enhance the quality, utility, and clarity of the information being collected; and (4) ways to minimize the burden to respondents, including use of automated information collection techniques or other forms of information technology. Before including your address, phone number, e-mail address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

Dated: May 18, 2009.

Cartina Miller,

NPS Information Collection Clearance Officer.

[FR Doc. E9–12070 Filed 5–22–09; 8:45 am]

BILLING CODE 4310–52–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[AA–6665–C, AA–6665–A2; AK–964–1410–KC–P]

Alaska Native Claims Selection

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of decision approving lands for conveyance.

SUMMARY: As required by 43 CFR 2650.7(d), notice is hereby given that an appealable decision approving the surface estate for conveyance pursuant to the Alaska Native Claims Settlement Act will be issued to Isanotski Corporation. The lands are in the vicinity of False Pass, Alaska, and are located in:

Seward Meridian, Alaska

T. 62 S., R. 92 W.,
Secs. 31 and 32.

Containing approximately 432 acres.

T. 63 S., R. 92 W.,
Secs. 4, 5, and 6; Secs. 9, 10, and 15; Secs. 16, 22, and 27.

Containing approximately 3,313 acres.

T. 62 S., R. 93 W.,
Secs. 35 and 36.

Containing approximately 383 acres.

T. 63 S., R. 93 W.,
Secs. 1, 9, and 10; Secs. 15 and 16.

Containing approximately 2,998 acres.

T. 60 S., R. 94 W.,
Secs. 14 to 17, inclusive.

Containing approximately 2,236 acres.

T. 62 S., R. 94 W.,
Secs. 4 to 9, inclusive.

Containing approximately 3,794 acres.
Aggregating approximately 13,156 acres.

These lands lie entirely within the boundaries of the Aleutian Islands National Wildlife Refuge, withdrawn by Executive Order 1733, now known as the Alaska Maritime National Wildlife Refuge. The subsurface estate will be reserved to the United States in the conveyance to Isanotski Corporation. Notice of the decision will also be published four times in the Anchorage Daily News.

DATES: The time limits for filing an appeal are:

1. Any party claiming a property interest which is adversely affected by the decision shall have until June 25, 2009 to file an appeal.

2. Parties receiving service of the decision by certified mail shall have 30 days from the date of receipt to file an appeal.

Parties who do not file an appeal in accordance with the requirements of 43 CFR Part 4, Subpart E, shall be deemed to have waived their rights.

ADDRESSES: A copy of the decision may be obtained from: Bureau of Land Management, Alaska State Office, 222 West Seventh Avenue, #13, Anchorage, Alaska 99513–7504.

FOR FURTHER INFORMATION CONTACT: The Bureau of Land Management by phone at 907–271–5960, or by e-mail at *ak.blm.conveyance@ak.blm.gov.* Persons who use a telecommunication device

(TTD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8330, 24 hours a day, seven days a week, to contact the Bureau of Land Management.

Michael Bilancione,

Land Transfer Resolution Specialist, Land Transfer Adjudication I.

[FR Doc. E9–12052 Filed 5–22–09; 8:45 am]

BILLING CODE 4310–JA–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

[FWS–R3–R–2009–N0023; 30136–1265–0000–S3]

Seney National Wildlife Refuge, Schoolcraft County, MI

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of availability: Final Comprehensive Conservation Plan and Finding of No Significant Impact for Environmental Assessment.

SUMMARY: We, the U.S. Fish and Wildlife Service (Service), announce the availability of the Final Comprehensive Conservation Plan (CCP) and Finding of No Significant Impact (FONSI) for the Environmental Assessment (EA) for Seney National Wildlife Refuge (NWR). Goals and objectives in the CCP describe how the agency intends to manage the refuge over the next 15 years.

ADDRESSES: Copies of the Final CCP and FONSI/EA may be viewed at the Seney National Wildlife Refuge Headquarters or at public libraries near the refuge. You may access and download a copy via the Planning Web site at *http://www.fws.gov/midwest/Planning/Seney,* or you may obtain a copy on compact disk by contacting: U.S. Fish and Wildlife Service, Division of Conservation Planning, Bishop Henry Whipple Federal Building, 1 Federal Drive, Fort Snelling, MN 55111 (1–800–247–1247, extension 5429), or Seney National Wildlife Refuge, 1674 Refuge Entrance Road, Seney, MI 49883 (906–586–9851). A limited number of hardcopies will be available for distribution at the Refuge Headquarters.

FOR FURTHER INFORMATION CONTACT: Greg McClellan (906–586–9851).

SUPPLEMENTARY INFORMATION:

Introduction

With this notice, we complete the CCP process for Seney NWR, which we began by publishing a notice of intent on April 21, 2006 (71 FR 20722). For more information about the initial process, see that notice. We released the draft CCP and EA to the public, announcing and requesting comments in a notice of availability on September 3, 2008 (73 FR 51506).

Seney NWR was established in 1935 by Executive Order under the Migratory Bird Conservation Act for the protection and production of migratory birds and other wildlife. The Refuge encompasses approximately 95,238 acres; 25,150 acres comprise the Seney Wilderness Area in which is contained the Strangmoor Bog National Natural Landmark. The Refuge is also responsible for the 33-acre Whitefish Point Unit, a former Coast Guard Station at Whitefish Point, in Chippewa County.

The Draft CCP/EA was released for public review September 3, 2008; the comment period lasted 35 days ending October 8, 2008. During the comment period the Refuge hosted an open house event. By the conclusion of the comment period we received 14 written responses from organizations and individuals. In response to these comments we made a number of minor edits to the final document.

Selected Alternative

After considering the comments received, we have selected Alternative 2 (Management Gradients) for implementation. Under the selected alternative the Refuge will strive to manage its forests and water to allow unfettered succession to take place. Dynamic events such as windstorms, insect and tree disease outbreaks, and flooding and wildfire will play a more substantial role in shaping habitats.

The major focus of the Refuge for the next 15 years will be on increasing biodiversity and regional resource conservation priority species habitat. The Refuge will be segmented into four general units with a management strategy tied to each unit. The units would follow a general gradient of management from low intensity (wilderness) to higher manipulation (managed impoundments and visitor use). The Refuge will also seek to increase wildlife-dependent public use opportunities.

Background

The National Wildlife Refuge System Administration Act of 1966, as amended by the National Wildlife Refuge System Improvement Act of 1997 (16 U.S.C. 668dd–668ee *et seq.*), requires the Service to develop a CCP for each National Wildlife Refuge. The purpose in developing a CCP is to provide refuge managers with a 15-year strategy for achieving refuge purposes and contributing toward the mission of the National Wildlife Refuge System, consistent with sound principles of fish and wildlife management, conservation, legal mandates, and Service policies. In addition to outlining broad management direction for conserving wildlife and their habitats, the CCP identifies wildlife-dependent recreational opportunities available to the public, including opportunities for hunting, fishing, wildlife observation and photography, and environmental education and interpretation.

We will review and update the CCP at least every 15 years in accordance with the National Wildlife Refuge System Administration Act of 1966, as amended by the National Wildlife Refuge System Improvement Act of 1997, and the National Environmental Policy Act of 1969 (42 U.S.C. 4321–4370d).

Dated: March 12, 2009.

Charles M. Wooley,

Acting Regional Director, U.S. Fish and Wildlife Service, Fort Snelling, Minnesota.

[FR Doc. E9–12116 Filed 5–22–09; 8:45 am]

BILLING CODE 4310–55–P

DEPARTMENT OF THE INTERIOR

National Park Service

Notice of Inventory Completion: Field Museum of Natural History, Chicago, IL

AGENCY: National Park Service, Interior.

ACTION: Notice.

Notice is here given in accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), 25 U.S.C. 3003, of the completion of an inventory of human remains in the possession of the Field Museum of Natural History, Chicago, IL. The human remains were removed from Aliulik Peninsula, Kodiak Island, AK.

This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA, 25 U.S.C. 3003 (d)(3). The determinations in this notice are the sole responsibility of the museum, institution, or Federal agency that has control of the Native American human remains. The National Park Service is not responsible for the determinations in this notice.

A detailed assessment of the human remains was made by Field Museum of Natural History professional staff in consultation with professional staff of the Alutiiq Museum and Archaeological Repository, Kodiak, AK, on behalf of Akhiok-Kaguyak, Inc.; Kaguyak Village; Koniag, Inc.; and Native Village of Akhiok.

In 1950, human remains representing a minimum of one individual were removed from the the Alitak Bay side of the Aliulik Peninsula, Kodiak Island, AK, by Arthur Freeman, who donated them to the Field Museum of Natural History in 1983 (Field Museum of Natural History accession number 3566, catalog number 242601). No known individual was identified. No associated funerary objects are present.

The human remains have been identified as Native American based on specific cultural and geographic attributions in Field Museum of Natural History records. The records identify the human remains as ''probably Koniag, Eskimo'' from the ''Alitak Bay side of Aliulik Peninsula (154W 56' 50''N), Kodiak, Alaska.'' Koniag Eskimo - a term used by anthropologists to refer to both the late prehistoric and historic Native peoples of the Kodiak region - are the ancestors of the contemporary Kodiak Alutiiq people. Specifically, the human remains are from an area of the Kodiak archipelago traditionally used by shareholders and citizens of Akhiok-Kaguyak, Inc.; Kaguyak Village; Koniag, Inc.; and Native Village of Akhiok.

Officials of the Field Museum of Natural History have determined that, pursuant to 25 U.S.C. 3001 (9–10), the human remains described above represent the physical remains of one individual of Native American ancestry. Officials of the Field Museum of Natural History also have determined that, pursuant to 25 U.S.C. 3001 (2), there is a relationship of shared group identity that can be reasonably traced between the Native American human remains and Akhiok-Kaguyak, Inc.; Kaguyak Village; Koniag, Inc.; and Native Village of Akhiok.

Representatives of any other Indian tribe that believes itself to be culturally affiliated with the human remains should contact Helen Robbins, Repatriation Director, Field Museum of Natural History, 1400 South Lake Shore Drive, Chicago, IL 60605–2496, telephone (312) 665–7317, before June 25, 2009. Repatriation of the human remains to Akhiok-Kaguyak, Inc.; Kaguyak Village; Koniag, Inc.; and Native Village of Akhiok may proceed after that date if no additional claimants come forward.

The Field Museum of Natural History is responsible for notifying Akhiok-Kaguyak, Inc.; Kaguyak Village; Koniag, Inc.; and Native Village of Akhiok that this notice has been published.

Dated: May 6, 2009

Sherry Hutt,

Manager, National NAGPRA Program.

[FR Doc. E9–12289 Filed 5–22–09; 8:45 am]

BILLING CODE 4312–50–S

DEPARTMENT OF THE INTERIOR

National Park Service

Notice of Inventory Completion: Field Museum of Natural History, Chicago, IL

AGENCY: National Park Service, Interior.

ACTION: Notice.

Notice is here given in accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), 25 U.S.C. 3003, of the completion of an inventory of human remains in the possession of the Field Museum of Natural History, Chicago, IL. The human remains were removed from Uyak Bay, Kodiak Island, AK.

This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA, 25 U.S.C. 3003 (d)(3). The determinations in this notice are the sole responsibility of the museum, institution, or Federal agency that has control of the Native American human remains. The National Park Service is not responsible for the determinations in this notice.

A detailed assessment of the human remains was made by Field Museum of Natural History professional staff in consultation with professional staff of the Alutiiq Museum and Archaeological Repository, Kodiak, AK, on behalf of Koniag, Inc. and Native Village of Larsen Bay.

In 1967, human remains representing a minimum of one individual were removed from the vicinity of Uyak Bay, Kodiak Island, AK, by Kenneth G. McQuin, who donated them to the Field Museum of Natural History that same year (Field Museum of Natural History accession number 2983, catalog number 193459). No known individual was identified. No associated funerary objects are present.

The human remains have been identified as Native American based on specific cultural and geographic attributions in Field Museum of Natural History records. The records identify the human remains as ''Koniag Eskimo'' from ''Uyak Bay, Kodiak Island, Alaska.'' Koniag Eskimo - a term used by anthropologists to refer to both the late prehistoric and historic Native peoples of the Kodiak region - are the ancestors of the contemporary Kodiak Alutiiq people. Specifically, the human remains are from an area of the Kodiak archipelago traditionally used by shareholders and citizens of Koniag, Inc. and Native Village of Larsen Bay.

Officials of the Field Museum of Natural History have determined that, pursuant to 25 U.S.C. 3001 (9–10), the human remains described above represent the physical remains of one individual of Native American ancestry. Officials of the Field Museum of Natural History also have determined that, pursuant to 25 U.S.C. 3001 (2), there is a relationship of shared group identity that can be reasonably traced between the Native American human remains and Koniag, Inc. and Native Village of Larsen Bay.

Representatives of any other Indian tribe that believes itself to be culturally affiliated with the human remains should contact Helen Robbins, Repatriation Director, Field Museum of Natural History, 1400 South Lake Shore Drive, Chicago, IL 60605–2496, telephone (312) 665–7317, before June 25, 2009. Repatriation of the human remains to Koniag, Inc. and Native Village of Larsen Bay may proceed after that date if no additional claimants come forward.

The Field Museum of Natural History is responsible for notifying Koniag, Inc. and Native Village of Larsen Bay that this notice has been published.

Dated: May 6, 2009

Sherry Hutt,

Manager, National NAGPRA Program.

[FR Doc. E9–12288 Filed 5–22–09; 8:45 am]

BILLING CODE 4312–50–S

DEPARTMENT OF THE INTERIOR

National Park Service

Notice of Inventory Completion: U.S. Department of the Interior, National Park Service, Fort Vancouver National Historic Site, Vancouver, WA

AGENCY: National Park Service, Interior.

ACTION: Notice.

Notice is here given in accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), 25 U.S.C. 3003, of the completion of an inventory of human remains in the possession and control of the U.S. Department of the Interior, National Park Service, Fort Vancouver National Historic Site, Vancouver, WA. The human remains were removed from Clark County, WA.

This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA, 25 U.S.C. 3003 (d)(3). The determinations in this notice are the sole responsibility of the superintendent, Fort Vancouver National Historic Site.

A detailed assessment of the human remains was made by Fort Vancouver National Historic Site professional staff in consultation with representatives of the Confederated Tribes and Bands of the Yakama Nation, Washington; Confederated Tribes of the Chehalis Reservation, Washington; Confederated Tribes of the Grand Ronde Community of Oregon; Confederated Tribes of the Siletz Reservation, Oregon; Confederated Tribes of the Umatilla Indian Reservation, Oregon; Confederated Tribes of the Warm Springs Reservation of Oregon; Cowlitz Indian Tribe, Washington; Muckleshoot Indian Tribe of the Muckleshoot Reservation, Washington; Nisqually Indian Tribe of the Nisqually Reservation, Washington; Snoqualmie Tribe, Washington; Spokane Tribe of the Spokane Reservation, Washington; Stillaguamish Tribe of Washington; and three non-Federally recognized Indian groups – Clatsop-Nehalem Confederated Tribes, Snoqualmoo Tribe, and Wanapum Band.

In the 1950s, human remains representing a minimum of nine individuals were removed from the I–5 corridor in Clark County, WA. The human remains were displaced by I–5 construction and donated to Fort Vancouver National Historic Site. No known individuals were identified. No associated funerary objects are present.

In 1977, human remains representing a minimum of two individuals were removed from the village area of Fort Vancouver in Clark County, WA, during archeological excavations in preparation for planned modifications to State Route 14. No known individuals were identified. No associated funerary objects are present.

The age of the human remains is unknown and no other information is available about either of the sites from which they were removed. The available evidence is insufficient to identify an earlier group and therefore it is not possible to make a determination of cultural affiliation.

Officials of Fort Vancouver National Historic Site have determined that, pursuant to 25 U.S.C. 3001 (9–10), the human remains described above represent the physical remains of 11 individuals of Native American ancestry. Officials of Fort Vancouver National Historic Site also have determined that, pursuant to 25 U.S.C. 3001 (2), a relationship of shared group identity cannot reasonably be traced between the Native American human remains and any present-day Indian tribe.

The Native American Graves Protection and Repatriation Review Committee (Review Committee) is responsible for recommending specific actions for disposition of culturally unidentifiable human remains. In August 2008, Fort Vancouver National Historic Site requested that the Review Committee recommend disposition of the 11 culturally unidentifiable human remains to the Vancouver Inter-Tribal Consortium on behalf of the following signatories: Clatsop-Nehalem Confederated Tribes; Confederated Tribes and Bands of the Yakama Nation, Washington; Confederated Tribes of the Chehalis Reservation, Washington; Confederated Tribes of the Grand Ronde Community of Oregon; Confederated Tribes of the Siletz Reservation, Oregon; Confederated Tribes of the Umatilla Indian Reservation, Oregon; Confederated Tribes of the Warm Springs Reservation of Oregon; Cowlitz Indian Tribe, Washington; Muckleshoot Indian Tribe of the Muckleshoot Reservation, Washington; Nisqually Indian Tribe of the Nisqually Reservation, Washington; Snoqualmie Tribe, Washington; Snoqualmoo Tribe; Spokane Tribe of the Spokane Reservation, Washington; Stillaguamish Tribe of Washington; and Wanapum Band. All have historical connections to present-day Vancouver, WA, and have requested the human remains through the Vancouver Inter-Tribal Consortium. The Review Committee considered the proposal at its October 11–12, 2008 meeting and recommended disposition of the human remains to the Vancouver Inter-Tribal Consortium on behalf of the Clatsop-Nehalem Confederated Tribes; Confederated Tribes and Bands of the Yakama Nation, Washington; Confederated Tribes of the Chehalis Reservation, Washington; Confederated Tribes of the Grand Ronde Community of Oregon; Confederated Tribes of the Siletz Reservation, Oregon; Confederated Tribes of the Umatilla Indian Reservation, Oregon; Confederated Tribes of the Warm Springs Reservation of Oregon; Cowlitz Indian Tribe, Washington; Muckleshoot Indian Tribe of the Muckleshoot Reservation, Washington; Nisqually Indian Tribe of the Nisqually Reservation, Washington; Snoqualmie Tribe, Washington; Snoqualmoo Tribe; Spokane Tribe of the Spokane Reservation, Washington; Stillaguamish Tribe of Washington; and Wanapum Band.

An April 3, 2009 letter on behalf of the Secretary of the Interior from the Designated Federal Official transmitted the authorization for the park to effect disposition of the physical remains of the culturally unidentifiable individuals to the Vancouver Inter-Tribal Consortium on behalf of the 15 Indian tribes listed above contingent on the publication of a Notice of Inventory Completion in the **Federal Register**. This notice fulfills that requirement.

Representatives of any other Indian tribe that believes itself to be culturally affiliated with the human remains should contact Tracy Fortmann, superintendent, Fort Vancouver National Historic Site, 612 E. Reserve St., Vancouver, WA 98661–3897, telephone (360) 816–6205, before June 25, 2009. Disposition of the human remains to the Vancouver Inter-Tribal Consortium on behalf of the Clatsop-Nehalem Confederated Tribes; Confederated Tribes and Bands of the Yakama Nation, Washington; Confederated Tribes of the Chehalis Reservation, Washington; Confederated Tribes of the Grand Ronde Community of Oregon; Confederated Tribes of the Siletz Reservation, Oregon; Confederated Tribes of the Umatilla Indian Reservation, Oregon; Confederated Tribes of the Warm Springs Reservation of Oregon; Cowlitz Indian Tribe, Washington; Muckleshoot Indian Tribe of the Muckleshoot Reservation, Washington; Nisqually Indian Tribe of the Nisqually Reservation, Washington; Snoqualmie Tribe, Washington; Snoqualmoo Tribe; Spokane Tribe of the Spokane Reservation, Washington; Stillaguamish Tribe of Washington; and Wanapum Band may proceed after that date if no additional claimants come forward.

Fort Vancouver National Historic Site is responsible for notifying the Confederated Tribes and Bands of the Yakama Nation, Washington; Confederated Tribes of the Chehalis Reservation, Washington; Confederated Tribes of the Grand Ronde Community of Oregon; Confederated Tribes of the Siletz Reservation, Oregon; Confederated Tribes of the Umatilla Indian Reservation, Oregon; Confederated Tribes of the Warm Springs Reservation of Oregon; Cowlitz Indian Tribe, Washington; Muckleshoot Indian Tribe of the Muckleshoot Reservation, Washington; Nisqually Indian Tribe of the Nisqually Reservation, Washington; Snoqualmie Tribe, Washington; Spokane Tribe of the Spokane Reservation, Washington; Stillaguamish Tribe of Washington; and three non-Federally recognized Indian groups – Clatsop-Nehalem Confederated Tribes, Snoqualmoo Tribe, and Wanapum Band that this notice has been published.

Dated: May 5, 2009.

Sherry Hutt,

Manager, National NAGPRA Program.

[FR Doc. E9–12282 Filed 5–22–09; 8:45 am]

BILLING CODE 4312–50–S

DEPARTMENT OF THE INTERIOR

National Park Service

Notice of Inventory Completion: Paul H. Karshner Memorial Museum, Puyallup, WA

AGENCY: National Park Service, Interior.

ACTION: Notice.

Notice is here given in accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), 25 U.S.C. 3003, of the completion of an inventory of human remains in the possession of Paul H. Karshner Memorial Museum, Puyallup, WA. The human remains were removed from Decatur Island, San Juan County, WA.

This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA, 25 U.S.C. 3003 (d)(3). The determinations in this notice are the sole responsibility of the museum, institution, or Federal agency that has control of the Native American human remains. The National Park Service is not responsible for the determinations in this notice.

A detailed assessment of the human remains was made by Paul H. Karshner Memorial Museum professional staff in consultation with representatives of the Lummi Tribe of the Lummi Reservation, Washington; Samish Indian Nation, Washington; Swinomish Indian Tribal Community of the Swinomish Reservation, Washington; and Tulalip Tribes of the Tulalip Reservation, Washington.

In or prior to 1930, human remains representing a minimum of one individual were removed from Decatur Island in San Juan County, WA. The human remains were donated to the museum by its founder, Dr. Warner M. Karshner, in 1930 (Catalog #1–362, Accn. #1930.01). No known individual was identified. No associated funerary objects are present.

The human remains are listed in the museum inventory as being from Decatur Island and described as ''one flattened Indian skull'' (museum inventory notebook). Further, a direct label on the cranium states ''Decatur Island, Puget Sound'' as the place of origin. Based on these records, the human remains have been determined by the museum to be Native American.

Decatur Island is located within the San Juan Islands, an archipelago that is known to have been utilized by the aboriginal Lummi, Samish, and Swinomish tribes or bands. During the consultation process with the Lummi Tribe, representatives of the Lummi indicated they would not claim the human remains because they consider Decatur Island to be outside of their usual and accustomed places. Both the Samish Indian Nation and Swinomish Indian Tribal Community have submitted claims to the Paul H. Karshner Memorial Museum for human remains from Decatur Island, and each tribe provided evidence regarding aboriginal use of Decatur Island. During the consultation process, representatives of the Swinomish Indian Tribal Community stated that they consider Decatur Island to have been used primarily by the aboriginal Samish, to which the Swinomish Indian Tribal Community is an adjudicated legal successor in interest (United States v. Washington, 459 F. Supp. 1020, 1039 (W.D. Wa. 1978)). During the consultation process, representatives of the Samish Indian Nation stated that they consider Decatur Island to be within their traditional territory and provided evidence that other human remains from Decatur Island have been repatriated to the Samish Indian Nation. Following consultation between the Swinomish Indian Tribal Community and Samish Indian Nation, the Swinomish Indian Tribal Community provided the museum with a written statement withdrawing their claim for the human remains from Decatur Island. With the voluntarily withdrawal of the claim for repatriation of the human remains by Swinomish Indian Tribal Community, officials of the Paul H. Karshner Memorial Museum have determined that there is a preponderance of evidence in favor of the Samish Indian Nation's claim for repatriation. Both the Swinomish Indian Tribal Community and Samish Indian Nation have agreed to work cooperatively with respect to reburial of the human remains after the repatriation is complete.

Officials of the Paul H. Karshner Memorial Museum have determined that, pursuant to 25 U.S.C. 3001 (9–10), the human remains described above represent the physical remains of one individual of Native American ancestry. Officials of the Paul H. Karshner Memorial Museum also have determined that, pursuant to 25 U.S.C. 3001 (2), there is a relationship of shared group identity that can be reasonably traced between the Native American human remains and the Samish Indian Nation, Washington and Swinomish Indian Tribal Community of the Swinomish Reservation, Washington.

Representatives of any other Indian tribe that believes itself to be culturally affiliated with the human remains should contact Dr. Jay Reifel, Assistant Superintendent, Paul H. Karshner Memorial Museum, telephone (253) 840–8971, or Ms. Beth Bestrom, Museum Curator, Paul H. Karshner Memorial Museum, telephone (253) 841–8748, 309 4th St. NE, Puyallup, WA 98372, before June 25, 2009. Repatriation of the human remains to the Samish Indian Nation, Washington may proceed after that date if no additional claimants come forward.

The Paul H. Karshner Memorial Museum is responsible for notifying the Lummi Tribe of the Lummi Reservation, Washington; Samish Indian Nation, Washington; Swinomish Indian Tribal Community of the Swinomish Reservation, Washington; and Tulalip Tribes of the Tulalip Reservation, Washington that this notice has been published.

Dated: April 28, 2009.

Sherry Hutt,

Manager, National NAGPRA Program.

[FR Doc. E9–12281 Filed 5–22–09; 8:45 am]

BILLING CODE 4312–50–S

DEPARTMENT OF THE INTERIOR

National Park Service

Notice of Inventory Completion: Oregon State University, Department of Anthropology, Corvallis, OR

AGENCY: National Park Service, Interior.

ACTION: Notice.

Notice is here given in accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), 25 U.S.C. 3003, of the completion of an inventory of human remains in the control of Oregon State University, Department of Anthropology, Corvallis, OR. The human remains were removed from Fisher Mounds, Will County, IL.

This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA, 25 U.S.C. 3003 (d)(3). The determinations in this notice are the sole responsibility of the museum, institution, or Federal agency that has control of the Native American human remains. The National Park Service is not responsible for the determinations in this notice.

A detailed assessment of the human remains was made by Oregon State University, Department of Anthropology professional staff in consultation with representatives of the Ho-Chunk Nation of Wisconsin and the Iowa Tribe of Kansas and Nebraska. The Cheyenne River Sioux Tribe of the Cheyenne River Reservation, South Dakota; Citizen

Potawatomi Nation, Oklahoma; Delaware Nation, Oklahoma; Forest County Potawatomi Community, Wisconsin; Hannahville Indian Community, Michigan; Iowa Tribe of Oklahoma; Kickapoo Tribe of Indians of the Kickapoo Reservation in Kansas; Kickapoo Tribe of Oklahoma; Oglala Sioux Tribe of the Pine Ridge Reservation, South Dakota; Otoe-Missouria Tribe of Indians, Oklahoma; Peoria Tribe of Indians of Oklahoma; Pokagon Band of Potawatomi Indians, Michigan and Indiana; Prairie Band of Potawatomi Nation, Kansas; Sac & Fox Tribe of the Mississippi in Iowa; Sac & Fox Nation of Missouri in Kansas and Nebraska; and Winnebago Tribe of Nebraska were notified, but did not participate in consultation on the human remains described in this notice.

On an unknown date, human remains representing a minimum of one individual were removed from Fisher Mounds, Will County, IL, by an unknown individual. In 1976, the human remains were donated to the Department of Anthropology by the son of Georg Karl Neumann. Dr. Neumann worked as a physical anthropologist for Indiana State University, Terre Haute, IN. No known individual was identified. No associated funerary objects are present.

Museum records indicate that the human remains are identified as ''3EM.'' According to the culturally unidentifiable (CUI) database of the National NAGPRA Program in the CUI inventory for Indiana State University, ''3EM'' is used to identify human remains from the Fisher Mound group in Will County, IL (East Mound). Dr. Neumann's notes identify the human remains as 3EM108. Officials at the University of Oregon, Department of Anthropology reasonably believe that, based on these records, the individual is most likely from the Fisher Mounds site.

The Fisher Mounds are located in northeastern Illinois, 60 miles southwest of Chicago, on the south bank of the Des Plaines River, approximately one mile north of the confluence of the Des Plaines and Kankakee Rivers. Formerly, the Fisher Mounds were part of the Cornelius Estate, also known as the Dan Fisher Farm. Excavation at the Fisher Farm took place during the early 20th century. The site comprises a large village with numerous house floors and pits, as well as 12 mounds. Several mounds were found to contain burials of Native Americans along with native artifacts. Thousands of human remains and items were unearthed from the multiple layers of burials within the mounds, with each layer constituting a different occupational period. According to George Langford, Sr., who also excavated the area, the burials from the small east mound most likely date to the late 18th century.

Native tribes in Illinois belonged to the Algonquian linguistic family. Tribes inhabiting northeast Illinois included the Miami, Mascouten and Illinois. During the latter half of the 1700s, the Winnebago and Shawnee lived in the area. Early 18th century migrations and forced relocation from the east brought the Sauk, Fox, Kickapoo and Potawatomi into the area. The Mascouten became part of the Kickapoo after 1800. In 1854, tribes associated with the Miami and the Illinois became associated with the Confederated Peoria, and by 1873 they became known as the United Peoria and Miamis. Later periods, the Miami tribe associated with the Potawatomi, Shawnee, and Delaware. Therefore, the tribes that occupied Illinois at the close of the 18th century are the Mascouten, Miami, Illinois, Sauk, Fox, Kickapoo, Shawnee, Potawatomi, and Winnebago.

The Ho-Chunk Nation of Wisconsin; Iowa Tribe of Kansas and Nebraska; Otoe-Missouria Tribe of Indians, Oklahoma; and Winnebago Tribe of Nebraska have provided both written and oral history for their traditional occupation of Midwest areas east of the Mississippi and have demonstrated land claims in Illinois. In addition, published works cite the Ho-Chunk Nation of Wisconsin; Iowa Tribe of Kansas and Nebraska; Iowa Tribe of Oklahoma; Otoe-Missouria Tribe of Indians, Oklahoma; and the Winnebago Tribe of Nebraska, as having had villages in Illinois characterized by mound-building cultural practices.

Based on the preponderance of the evidence, including the primary body of Dr. Neumann's work in Illinois, collection records, and oral history, officials of the Oregon State University Department of Anthropology reasonably believe that the descendants of these Mascouten, Miami, Illinois, Sauk, Fox, Kickapoo, Shawnee, Potawatomi, and Winnebago are members of the Citizen Potawatomi Nation of Oklahoma; Forest County Potawatomi Community of Wisconsin; Hannahville Indian Community, Michigan; Ho-Chunk Nation of Wisconsin; Iowa Tribe of Kansas and Nebraska; Iowa Tribe of Oklahoma; Kickapoo Tribe of Indians of the Kickapoo Reservation in Kansas; Kickapoo Tribe of Oklahoma; Otoe-Missouria Tribe of Indians of Oklahoma; Peoria Tribe of Indians of Oklahoma; Pokagon Band of Potawatomi Indians of Michigan and Indiana; Prairie Band of Potawatomi Nation of Kansas; Sac & Fox Tribe of the Mississippi in Iowa; Sac & Fox Nation of Missouri in Kansas and Nebraska; Sac & Fox Nation of Oklahoma; Shawnee Tribe, Oklahoma; and Winnebago Tribe of Nebraska.

Officials of the Oregon State University, Department of Anthropology have determined that, pursuant to 25 U.S.C. 3001 (9–10), the human remains described above represent the physical remains of one individual of Native American ancestry. Officials of the Oregon State University, Department of Anthropology also have determined that, pursuant to 25 U.S.C. 3001 (2), there is a relationship of shared group identity that can be reasonably traced between the Native American human remains and the Citizen Potawatomi Nation of Oklahoma; Forest County Potawatomi Community of Wisconsin; Hannahville Indian Community, Michigan; Ho-Chunk Nation of Wisconsin; Iowa Tribe of Kansas and Nebraska; Iowa Tribe of Oklahoma; Kickapoo Tribe of Indians of the Kickapoo Reservation in Kansas; Kickapoo Tribe of Oklahoma; Miami Tribe of Oklahoma; Otoe-Missouria Tribe of Indians of Oklahoma; Peoria Tribe of Indians of Oklahoma; Pokagon Band of Potawatomi Indians of Michigan and Indiana; Prairie Band of Potawatomi Nation of Kansas; Sac & Fox Tribe of the Mississippi in Iowa; Sac & Fox Nation of Missouri in Kansas and Nebraska; Sac & Fox Nation of Oklahoma; Shawnee Tribe, Oklahoma; and Winnebago Tribe of Nebraska.

Representatives of any other Indian tribe that believes itself to be culturally affiliated with the human remains should contact Dr. David McMurray, Oregon State University, Department of Anthropology, 238 Waldo Hall, Corvallis, OR 97331, telephone (541) 737–4515, before June 25, 2009. Repatriation of the human remains to the Ho-Chunk Nation of Wisconsin and the Iowa Tribe of Kansas and Nebraska may proceed after that date if no additional claimants come forward.

The Oregon State University, Department of Anthropology is responsible for notifying the Cheyenne River Sioux Tribe of the Cheyenne River Reservation, South Dakota; Citizen Potawatomi Nation, Oklahoma; Delaware Nation, Oklahoma; Forest County Potawatomi Community, Wisconsin; Hannahville Indian Community, Michigan; Ho-Chunk Nation of Wisconsin; Iowa Tribe of Kansas and Nebraska; Iowa Tribe of Oklahoma; Kickapoo Tribe of Indians of the Kickapoo Reservation in Kansas; Kickapoo Tribe of Oklahoma; Miami Tribe of Oklahoma; Oglala Sioux Tribe of the Pine Ridge Reservation, South Dakota; Otoe-Missouria Tribe of Indians, Oklahoma; Peoria Tribe of Indians of Oklahoma; Pokagon Band of Potawatomi Indians, Michigan and Indiana; Prairie Band of Potawatomi Nation, Kansas; Sac & Fox Tribe of the Mississippi in Iowa; Sac & Fox Nation of Missouri in Kansas and Nebraska; Sac & Fox Nation of Oklahoma; Shawnee Tribe, Oklahoma; and Winnebago Tribe of Nebraska that this notice has been published.

Dated: May 11, 2009

Sherry Hutt,

Manager, National NAGPRA Program.

[FR Doc. E9–12256 Filed 5–22–09; 8:45 am]

BILLING CODE 4312–50–S

DEPARTMENT OF THE INTERIOR

National Park Service

Notice of Inventory Completion: Kalamazoo Valley Museum, Kalamazoo Valley Community College, Kalamazoo, MI

AGENCY: National Park Service, Interior.

ACTION: Notice.

Notice is here given in accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), 25 U.S.C. 3003, of the completion of an inventory of human remains in the possession of the Kalamazoo Valley Museum, Kalamazoo Valley Community College, Kalamazoo, MI. The human remains were most likely removed from Wayne County and unidentified mound builder settlements in Michigan.

This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA, 25 U.S.C. 3003 (d)(3). The determinations in this notice are the sole responsibility of the museum, institution, or Federal agency that has control of the Native American human remains. The National Park Service is not responsible for the determinations in this notice.

A detailed assessment of the human remains was made by the Kalamazoo Valley Museum professional staff in consultation with representatives of the Bay Mills Indian Community, Michigan; Grand Traverse Band of Ottawa and Chippewa Indians, Michigan; Keweenaw Bay Indian Community, Michigan; Lac Vieux Desert Band of Lake Superior Chippewa Indians, Michigan; Little Traverse Bay Bands of Odawa Indians, Michigan; Pokagon Band of Potawatomi Indians, Michigan and Indiana; Saginaw Chippewa Indian Tribe of Michigan; and Sault Ste. Marie Tribe of Chippewa Indians of Michigan.

Prior to 1946, human remains representing a minimum of one individual were removed as a surface find from an unidentified site in the area of Detroit, Wayne County, MI, by amateur collector Leo J. Dickey. Mr. Dickey donated the human remains to the Kalamazoo Museum (today the Kalamazoo Valley Museum) in 1951. No known individual was identified. No associated funerary objects are present.

The limited information provided by the donor for the human remains has been determined by museum officials to be insufficient to reasonably associate them to any present-day Indian tribe. Therefore, officials of the Kalamazoo Valley Museum have determined the Native American human remains are culturally unidentifiable.

At an unknown date, human remains representing two individuals were removed from an unidentified mound builder site (or sites) in Michigan. In 1946, during an inventory of the Kalamazoo Museum collection, the human remains were found uncataloged in the collection. They were identified as Native American ancestry based on handwritten labels affixed to the foreheads of the skulls reading ''Moundbuilder.'' A thorough search of museum records did not reveal the donor of the human remains or the date they arrived at the museum. The human remains were subsequently cataloged into the collection as Native American human remains of Michigan mound builder ancestry. No known individuals were identified. No associated funerary objects are present.

In June 2008, two anthropology professors from Western Michigan University examined the human remains and determined that they were consistent with Native American morphology. However, given the circumstances of the acquisition of the human remains, the museum staff has concluded that there is insufficient information to reasonably associate them to any present-day Indian tribe. Therefore, officials of the Kalamazoo Valley Museum have determined that the Native American human remains are culturally unidentifiable.

Officials of the Kalamazoo Valley Museum have determined that, pursuant to 25 U.S.C. 3001 (9–10), the human remains described above represent the physical remains of three individuals of Native American ancestry. Officials of the Kalamazoo Valley Museum also have determined that, pursuant to 25 U.S.C. 3001 (2), a shared group relationship cannot be reasonably traced between the Native American human remains and any present-day Indian tribe.

The Native American Graves Protection and Repatriation Review Committee (Review Committee) is responsible for recommending specific actions for disposition of culturally unidentifiable human remains. In October 2008, the Kalamazoo Valley Museum requested that the Review Committee recommend disposition of three culturally unidentifiable human remains to the Bay Mills Indian Community, Michigan; Grand Traverse Band of Ottawa and Chippewa Indians, Michigan; Keweenaw Bay Indian Community, Michigan; Lac Vieux Desert Band of Lake Superior Chippewa Indians, Michigan; Little Traverse Bay Bands of Odawa Indians, Michigan; Pokagon Band of Potawatomi Indians, Michigan and Indiana; Saginaw Chippewa Indian Tribe of Michigan; and Sault Ste. Marie Tribe of Chippewa Indians of Michigan, as the aboriginal occupants of Michigan.

The Review Committee considered the proposal at its October 11–12, 2008 meeting and recommended disposition of the human remains to the Bay Mills Indian Community, Michigan; Grand Traverse Band of Ottawa and Chippewa Indians, Michigan; Keweenaw Bay Indian Community, Michigan; Lac Vieux Desert Band of Lake Superior Chippewa Indians, Michigan; Little Traverse Bay Bands of Odawa Indians, Michigan; Pokagon Band of Potawatomi Indians, Michigan and Indiana; Saginaw Chippewa Indian Tribe of Michigan; and Sault Ste. Marie Tribe of Chippewa Indians of Michigan. An April 3, 2009 letter on behalf of the Secretary of Interior from the Designated Federal Officer, transmitted the authorization for the Kalamazoo Valley Museum to effect disposition of the human remains to the eight Indian tribes listed above contingent on the publication of a Notice of Inventory Completion in the **Federal Register**. This notice fulfills that requirement.

Representatives of any other Indian tribe that believes itself to be culturally affiliated with the human remains should contact Paula L. Metzner, Kalamazoo Valley Museum, P.O. Box 4070, Kalamazoo, MI 49003–4070, telephone (269) 373–7958, before June 25, 2009. Disposition of the human remains to the Bay Mills Indian Community, Michigan; Grand Traverse Band of Ottawa and Chippewa Indians, Michigan; Keweenaw Bay Indian Community, Michigan; Lac Vieux Desert Band of Lake Superior Chippewa Indians, Michigan; Little Traverse Bay Bands of Odawa Indians, Michigan; Pokagon Band of Potawatomi Indians, Michigan and Indiana; Saginaw Chippewa Indian Tribe of Michigan;

and Sault Ste. Marie Tribe of Chippewa Indians of Michigan may proceed after that date if no additional claimants come forward.

The Kalamazoo Valley Museum is responsible for notifying the Bay Mills Indian Community, Michigan; Grand Traverse Band of Ottawa and Chippewa Indians, Michigan; Keweenaw Bay Indian Community, Michigan; Lac Vieux Desert Band of Lake Superior Chippewa Indians, Michigan; Little Traverse Bay Bands of Odawa Indians, Michigan; Pokagon Band of Potawatomi Indians, Michigan and Indiana; Saginaw Chippewa Indian Tribe of Michigan; and Sault Ste. Marie Tribe of Chippewa Indians of Michigan that this notice has been published.

Dated: May 11, 2009.

Sherry Hutt,

Manager, National NAGPRA Program.

[FR Doc. E9–12252 Filed 5–22–09; 8:45 am]

BILLING CODE 4312–50–S

DEPARTMENT OF THE INTERIOR

National Park Service

Notice of Inventory Completion: Field Museum of Natural History, Chicago, IL

AGENCY: National Park Service, Interior.

ACTION: Notice.

Notice is here given in accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), 25 U.S.C. 3003, of the completion of an inventory of human remains in the possession of the Field Museum of Natural History, Chicago, IL. The human remains were removed from Karluk, Kodiak Island, AK.

This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA, 25 U.S.C. 3003 (d)(3). The determinations in this notice are the sole responsibility of the museum, institution, or Federal agency that has control of the Native American human remains. The National Park Service is not responsible for the determinations in this notice.

A detailed assessment of the human remains was made by Field Museum of Natural History professional staff in consultation with professional staff of the Alutiiq Museum and Archaeological Repository, Kodiak, AK, on behalf of Koniag, Inc.; Native Village of Karluk; and Native Village of Larsen Bay.

In 1893, employees of the Field Museum of Natural History purchased human remains representing one individual from Ward's Natural Science Establishment, Rochester, NY (Field Museum of Natural History accession number 407, catalog number 41471). No known individual was identified. No associated funerary objects are present.

The human remains have been identified as Native American based on specific cultural and geographic attributions in Field Museum of Natural History records. The records identify the human remains as ''Eskimo'' from an ''ancient dwelling at Karluk, Kodiak Isl., Alaska.'' The term ''Eskimo'' is used by anthropologists to refer to both the prehistoric and historic Native peoples of the Kodiak region, who are the ancestors of the present-day Alutiiq people. Specifically, the human remains are from an area of the Kodiak archipelago traditionally used by shareholders and citizens of Koniag, Inc.; Native Village of Karluk; and Native Village of Larsen Bay.

Officials of the Field Museum of Natural History have determined that, pursuant to 25 U.S.C. 3001 (9–10), the human remains described above represent the physical remains of one individual of Native American ancestry. Officials of the Field Museum of Natural History also have determined that, pursuant to 25 U.S.C. 3001 (2), there is a relationship of shared group identity that can be reasonably traced between the Native American human remains and Koniag, Inc.; Native Village of Karluk; and Native Village of Larsen Bay.

Representatives of any other Indian tribe that believes itself to be culturally affiliated with the human remains should contact Helen Robbins, Repatriation Director, Field Museum of Natural History, 1400 South Lake Shore Drive, Chicago, IL 60605–2496, telephone (312) 665–7317, before June 25, 2009. Repatriation of the human remains to Koniag, Inc.; Native Village of Karluk; and Native Village of Larsen Bay may proceed after that date if no additional claimants come forward.

The Field Museum of Natural History is responsible for notifying Koniag, Inc., Native Village of Karluk, and Native Village of Larsen Bay that this notice has been published.

Dated: May 6, 2009

Sherry Hutt,

Manager, National NAGPRA Program.

[FR Doc. E9–12291 Filed 5–22–09; 8:45 am]

BILLING CODE 4312–50–S

DEPARTMENT OF THE INTERIOR

National Park Service

National Register of Historic Places; Notification of Pending Nominations and Related Actions

Nominations for the following properties being considered for listing or related actions in the National Register were received by the National Park Service before May 9, 2009. Pursuant to section 60.13 of 36 CFR part 60, written comments concerning the significance of these properties under the National Register criteria for evaluation may be forwarded by United States Postal Service, to the National Register of Historic Places, National Park Service, 1849 C St., NW., 2280, Washington, DC 20240; by all other carriers, National Register of Historic Places, National Park Service,1201 Eye St. NW., 8th floor, Washington, DC 20005; or by fax, 202–371–6447. Written or faxed comments should be submitted by June 10, 2009.

J. Paul Loether,

Chief, National Register of Historic Places/ National Historic Landmarks Program.

CONNECTICUT

New Haven County

Christ Church New Haven, 70 Broadway, New Haven, 09000420.

INDIANA

Boone County

Traders Point Eagle Creek Rural Historic District, (Eagle Township and Pike Township, Indiana MPS) Roughly between I–865, I–465 and Lafayette Rd., Indianapolis, 09000433.

Traders Point Rural Historic District, (Eagle Township and Pike Township, Indiana MPS) Roughly bounded by IN 334, I–865, Old Hunt Club Rd. & CR 850 E., Zionsville, 09000421.

Clinton County

South Frankfort Historic District, Roughly between Walnut St., Prairie Creek, Meredith and Columbia Sts., Frankfort, 09000422.

Franklin County

Turrell, Salmon, Farmstead, 3051 Snow Hill Rd., West Harrison, 09000423.

Hancock County

Lincoln Park School, (Indiana's Public Common and High Schools MPS) 600 W. N. St., Greenfield, 09000424.

Hendricks County

Adams, Ora, House, 301–303 E. Main St., Danville, 09000425.

Huntington County

Chenoweth-Coulter Farm, 7067 S. Etna Rd., LaFontaine, 09000426.

Lake County

American Sheet and Tin Mill Apartment Building, (Concrete in Steel City: The Edison Concept Houses of Gary Indiana MS) 633 W. 4th Ave., Gary, 09000427.

Jackson-Monroe Terraces Historic District, (Concrete in Steel City: The Edison Concept Houses of Gary Indiana MS) 404–423 Jackson St. and 408–426 Monroe St., Gary, 09000428.

Monroe Terrace Historic District, (Concrete in Steel City: The Edison Concept Houses of Gary Indiana MS) 304–318 Monroe St., Gary, 09000429.

Polk Street Terraces Historic District, (Concrete in Steel City: The Edison Concept Houses of Gary Indiana MS) 404–422 and 437–455 Polk St., Gary, 09000430.

Marion County

Gibson Company Building, 433–447 N. Capitol Ave., Indianapolis, 09000431.

HCS Motor Car Company, 1402 N. Capitol Ave., Indianapolis, 09000432.

Traders Point Eagle Creek Rural Historic District, (Eagle Township and Pike Township, Indiana MPS) Roughly between I–865, I–465 and Lafayette Rd., Indianapolis, 09000433.

Switzerland County

Switzerland County Courthouse, 212 W. Main St., Vevay, 09000435.

Vanderburgh County

USS LST 325 (tank landing ship), 840 LST Dr., Evansville, 09000434.

MASSACHUSETTS

Essex County

Merrimack Associates Building, 25 Locust St., Haverhill, 09000436.

Middlesex County

Franklin School, 7 Stedman Rd., Lexington, 09000437.

Plymouth County

South Middleborough Historic District, Locust, Spruce, and Wareham Sts., Middleborough, 09000438.

MISSOURI

Cape Girardeau County

Vasterling, Julius, Building, (Cape Girardeau, Missouri MPS) 633–637 Broadway, Cape Girardeau, 09000439.

Jackson County

Hotel Otten, (Working Class Hotels at 19th and Main Streets, Kansas City, Missouri MPS) 2018–2020 Main St., Kansas City, 09000440.

St. Louis Independent city

Liggett & Myers Historic District, Roughly bounded by Vandeventer, Park, Thurman and Lafayette Aves., St. Louis, 09000441.

OHIO

Franklin County

Born Capital Brewery Bottling Works, 570 S. Front St., Columbus, 09000442.

Hamilton County

Hotel Metropole, 609 Walnut St., Cincinnati, 09000443.

Lawrence County

Selby Shoe Company Building, 1603 S. 3rd St., Ironton, 09000444.

SOUTH DAKOTA

Davison County

Hill, W.S., House, 520 E. 6th Ave., Mitchell, 09000445.

Fall River County

State Soldiers Home Barn, 2500 Minnekahta Ave., Hot Springs, 09000446.

Hughes County

Pierre Masonic Lodge, 201 W. Capitol Ave., Pierre, 09000447.

Lincoln County

Hudson Boy Scout Cabin, 416 Wheelock, Hudson, 09000448.

Perkins County

Central Perkins County Stockyard and Weighing Station, 1.5 mi. W. of Bison on SD 20, Bison, 09000449.

TEXAS

El Paso County

Mesa Pump Plant, 4901 Fred Wilson Ave., El Paso, 09000450.

Fayette County

Sengelmann Hall and City Meat Market Building, 527 and 529–533 N. Main St., Schulenburg, 09000451.

VIRGINIA

Charlottesville Independent city

Fifeville and Tonsler Neighborhoods Historic District, Bounded by Cherry Ave, to the S., the railway to the N., 4rth St., SW to the E., and Spring St., to the W., Charlottesville, 09000452/

WISCONSIN

Buffalo County

Harmonia Hall, S2119 Co. Hwy. E., Waumandee, 09000453.

WYOMING

Natrona County

Odd Fellows Building, 136 S. Wolcott St., Casper, 09000455.

Sublette County

Sommers Ranch Headquarters Historic District, 734 Co. Rd. 23–110, Pinedale, 09000454.

[FR Doc. E9–12073 Filed 5–22–09; 8:45 am]

BILLING CODE P

DEPARTMENT OF THE INTERIOR

National Park Service

National Register of Historic Places; Weekly Listing of Historic Properties

Pursuant to (36 CFR 60.13(b,c)) and (36 CFR 63.5), this notice, through publication of the information included herein, is to apprise the public as well as governmental agencies, associations and all other organizations and individuals interested in historic preservation, of the properties added to, or determined eligible for listing in, the National Register of Historic Places from April 6, to April 10, 2009.

For further information, please contact Edson Beall via: United States Postal Service mail, at the National Register of Historic Places, 2280, National Park Service, 1849 C St., NW., Washington, DC 20240; in person (by appointment), 1201 Eye St., NW., 8th floor, Washington, DC 20005; by fax, 202–371–2229; by phone, 202–354–2255; or by e-mail, *Edson_Beall@nps.gov.*

Dated: May 19, 2009.

J. Paul Loether,

Chief, National Register of Historic Places/ National Historic Landmarks Program.

KEY: State, County, Property Name, Address/ Boundary, City, Vicinity, Reference Number, Action, Date, Multiple Name

Arizona, Coconino County, Ice House, The, 201 E. Birch Ave., Flagstaff, 09000174, Listed, 4/08/09

California, Los Angeles County, Frank, Richard and Mary Alice, House, 919 La Loma Rd., Pasadena, 09000175, Listed, 4/10/09 (Cultural Resources of the Recent Past, City of Pasadena)

California, Los Angeles County, Marguerita Lane Historic District, Marguerita La. off South Morengo Ave., Pasadena, 09000177, Listed, 4/10/09

California, Los Angeles County, Mello, Clarence and Mary, House, 541 Fremont Dr., Pasadena, 09000178, Listed, 4/10/09 (Cultural Resources of the Recent Past, City of Pasadena)

California, Los Angeles County, Norton, John, House, 820 Burleigh Dr., Pasadena, 09000179, Listed, 4/10/09 (Cultural Resources of the Recent Past, City of Pasadena)

California, Los Angeles County, Pacific Electric Building, 610 S. Main St., Los Angeles, 09000180, Listed, 4/09/09

California, Los Angeles County, Pike, Robert and Barbara, House, 512 Glen Ct., Pasadena, 09000181, Listed, 4/10/09 (Cultural Resources of the Recent Past, City of Pasadena)

California, Placer County, Carnegie Library, 557 Lincoln St., Roseville, 09000199, Listed, 4/10/09

Florida, Sarasota County, Downtown Sarasota Historic District, Bound by 1st St., Orange Ave., State St., Gulf Stream Ave.

and N. Pineapple Ave., Sarasota, 09000183, Listed, 4/09/09

Georgia, Newton County, Brick Store, US 278 at Little River Rd./Social Circle Rd., Covington vicinity, 09000186, Listed, 4/09/09

Georgia, Walker County, Chickamauga Coal and Iron Company Coke Ovens, GA 341, Chickamauga, 09000188, Listed, 4/09/09

Kansas, Dickinson County, Eliason Barn, 147 KS 4, Gypsum, 09000189, Listed, 4/08/09 (Agriculture-Related Resources of Kansas)

Kansas, Ellis County, Mermis, J.A., House, 1401 Ash St., Hays, 09000190, Listed, 4/08/09

Kansas, Montgomery County, Brown Barn, 5879 Co. Rd. 4300, Independence, 09000191, Listed, 4/08/09 (Agriculture-Related Resources of Kansas)

Kansas, Ness County, Thornburg Barn, Co. Rd. A, 1.5 mi. W. of D Rd., Utica, 09000192, Listed, 4/08/09 (Agriculture-Related Resources of Kansas)

Kansas, Pottawatomie County, Teske Farmstead, 20795 Major Jenkins Rd., Onaga, 09000193, Listed, 4/08/09 (Agriculture-Related Resources of Kansas)

Kansas, Republic County, Shimanek Barn, 1806 220 Rd., Munden, 09000194, Listed, 4/08/09 (Agriculture-Related Resources of Kansas)

Kansas, Sheridan County, Shafer Barn, Co. Rd. 50S, 1.5 mi. W. of Co. Rd. 80E, Hoxie, 09000195, Listed, 4/08/09 (Agriculture-Related Resources of Kansas)

Wisconsin, Columbia County, Goeres Park, 101 Fair St., Lodi, 09000197, Listed, 4/09/09

Wisconsin, Columbia County, Lodi School Hillside Improvement Site, Corner St., bounded by Pleasant St. and Columbus St., Lodi, 09000198, Listed, 4/09/09

[FR Doc. E9–12072 Filed 5–22–09; 8:45 am]

BILLING CODE P

DEPARTMENT OF LABOR

Office of the Secretary

Submission for OMB Review: Comment Request

May 20, 2009.

The Department of Labor (DOL) hereby announces the submission of the following public information collection requests (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 each 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—Mine Safety and Health Administration (MSHA), Office of Management and Budget, 725 17th Street, NW., Room 10235, Washington, DC 20503, Telephone: 202–395–4816/Fax: 202–395–6974 (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 applicable 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: Mine Safety and Health Administration.

Type of Review: Extension without change of currently approved collection.

Title of Collection: Roof Control Plans.

OMB Control Number: 1219–0004.

Form Number: N/A.

Estimated Number of Respondents: 613.

Estimated Total Annual Burden Hours: 12,813.

Estimated Total Annual Cost Burden (does not include hourly wage costs): $7,020.

Affected Public: Business or other for profits (mines).

Description: In order to prevent occupational injuries resulting from falls of roofs, faces, and ribs, which are a leading cause of injuries and death in underground coal mines, all underground coal mine operators are required to develop and submit roof control plans to MSHA for evaluation and approval. These plans are evaluated to determine if they are adequate for prevailing mining conditions. For additional information, see related notice published at Vol. 74 FR 10779 on March 12, 2009.

Agency: Mine Safety and Health Administration.

Type of Review: Extension without change of currently approved collection.

Title of Collection: Notification of Methane Detected in Mine Atmosphere.

OMB Control Number: 1219–0103.

Form Number: N/A.

Estimated Number of Respondents: 8.

Estimated Total Annual Burden Hours: 36.

Estimated Total Annual Cost Burden (does not include hourly wage costs): $0.

Affected Public: Business or other for profits (mines).

Description: Methane is a flammable gas found in underground mining that presence can reduce the oxygen content when mixed with air, and consequently can act as an asphyxiant when present in large quantities. To help prevent accidents or injuries, MSHA requires operators of underground metal and nonmetal mines to notify MSHA of any change in methane conditions, *e.g.*, an outburst, a blowout, methane ignition, or methane occurrence of 0.25% or more. For additional information, see related notice published at Vol. 74 FR 9831 on March 6, 2009.

Agency: Mine Safety and Health Administration.

Type of Review: Extension without change of currently approved collection.

Title of Collection: Safety Standards for Roof Bolts in Metal and Nonmetal Mines and Underground Coal Mines.

OMB Control Number: 1219–0121.

Form Number: N/A.

Estimated Number of Respondents: 833.

Estimated Total Annual Burden Hours: 165.

Estimated Total Annual Cost Burden (does not include hourly wage costs): $0.

Affected Public: Business or other for profits (mines).

Description: Falls of roofs, faces, ribs, and highwalls in surface mines, historically, have been among the leading cause of injuries and deaths in mines. Therefore, in order to protect the safety of miners, mine operators are required to obtain certification from the manufacturers that roof and rock bolts and accessories are manufactured and tested in accordance with the applicable American Society for Testing and Materials (ASTM) specifications and make that certification available to an authorized representative of the Secretary. For additional information, see related notice published at Vol. 74 FR 9292 on March 3, 2009.

Agency: Mine Safety and Health Administration.

Type of Review: Extension without change of currently approved collection.

Title of Collection: Health Standards for Diesel Particulates (Underground Metal and Nonmetal Mines).

OMB Control Number: 1219–0135.

Form Number: N/A.

Estimated Number of Respondents: 173.

Estimated Total Annual Burden Hours: 3,331.

Estimated Total Annual Cost Burden (does not include hourly wage costs): $176,363.

Affected Public: Business or other for profits (mines).

Description: This collection pertains to safety requirements and safety standards for the maintenance and use of diesel equipment in underground metal and nonmetal mines to protect miners. The Diesel Particulate Matter (DPM) rule establishes a permissible exposure limit to total carbon, which is a surrogate for measuring a miner's exposure to DPM. The information collected is provided to the MSHA inspector and used by the agency to monitor the mine operator's compliance with the health standard. For additional information, see related notice published at Vol. 74 FR 11973 on March 20, 2009.

Darrin A. King,

Departmental Clearance Officer.

[FR Doc. E9–12127 Filed 5–22–09; 8:45 am]

BILLING CODE 4510–43–P

DEPARTMENT OF LABOR

Office of the Secretary

Submission for OMB Emergency Review: Comment Request

May 20, 2009.

The Department of Labor has submitted the following information collection request (ICR), utilizing emergency review procedures, to the Office of Management and Budget (OMB) for review and clearance in accordance with the Paperwork Reduction Act of 1995 (Pub. L. 104–13, 44 U.S.C. Chapter 35) and 5 CFR 1320.13. OMB approval has been requested by June 19, 2009. 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—Mine Safety and Health Administration (MSHA), Office of Management and Budget, Room 10235, Washington, DC 20503, Telephone: 202–395–7316/Fax: 202–395–6974 (these are not toll-free numbers), e-mail: *OIRA_submission@omb.eop.gov*. Comments and questions about the ICR listed below should be received no later than the requested OMB approval date. An additional opportunity to comment on this ICR will also be provided when DOL seeks approval under standard PRA clearance procedures pursuant to 5 CFR 1320.12, ''Clearance of collections of information in current rules.''

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 submissions of responses.

Agency: Mine Safety and Health Administration.

Title of Collection: Mine Rescue Teams for Underground Coal Mine Operators.

OMB Control Number: 1219–0144.

Affected Public: Underground coal mines.

Total Estimated Number of Respondents: 653.

Total Estimated Annual Burden Hours: 1,550.

Total Net Estimated Annual Costs Burden (other than hourly wage costs): $653.

Description: The respondents for this collection of information are underground coal mine operators. The records will be used by coal mine operators, supervisors, and employees, and State and Federal mine inspectors to provide assurance that each mine operator and mine rescue team is prepared for a mine emergency. The records show that the mine rescue team equipment has been examined and tested and is in good working order. The training records show that the mine rescue team members and the responsible persons at the mine are competent to respond to a mine emergency involving a fire, an explosion, or a gas or water inundation. The records greatly assist those who use them in making decisions that will ultimately affect the safety of all persons working underground.

These information collection requirements help assure that properly trained mine rescue teams are readily available to save endangered miners in life-threatening situations. In addition, the training requirements in this information collection will help assure the safety of the mine rescue team itself.

Why are we requesting Emergency Processing? The Mine Improvement and New Emergency Response Act of 2006 became effective on June 15, 2006 (MINER Act). The goal of the MINER Act is ''to improve the safety of mines and mining.'' To accomplish this goal, the MINER Act includes provisions to improve mine emergency response time, improve mine rescue team effectiveness, and increase the quantity and quality of mine rescue team training.

Section 4 of the MINER Act required MSHA to publish regulations on mine rescue teams. Because the mine rescue team provisions contained in Section 4 of the MINER Act apply only to underground coal mines, this rule will affect those mines and the mine rescue teams that cover them.

MSHA published a final rule revising the Agency's requirements for mine rescue teams for underground coal mines on February 8, 2008. The United Mine Workers of America challenged the final rule in the U.S. Court of Appeals for the District of Columbia Circuit. On February 10, 2009, the Court vacated the rule's provisions allowing mine-site and state-sponsored teams to train at small mines annually and State employees who are members of State-sponsored teams to substitute certain job duties for participation in one of two mine rescue contests required annually. The Court also vacated MSHA's conclusion in the preamble that State employees who are members of State-sponsored teams may participate in a mine rescue contest by serving as judges. See *Int'l Union, United Mine Workers of Am.* v. *Dep't of Labor*, 554 F.3d 150 (D.C. Cir. 2009).

Consistent with the Court's decision, MSHA is revising the existing rule to require mine-site and State-sponsored teams to train at small mines semiannually and State employees who are members of State-sponsored teams to participate in two mine rescue contests annually. An emergency review is necessary in order to obtain approval of the changes implemented by the aforementioned final rule which is being promulgated for reasons stated above and is effective upon publication.

Darrin A. King,

Departmental Clearance Officer.

[FR Doc. E9–12278 Filed 5–22–09; 8:45 am]

BILLING CODE 4510–43–P

DEPARTMENT OF LABOR

Employee Benefits Security Administration

145th Meeting of the Advisory Council on Employee Welfare and Pension Benefit Plans; Notice of Meeting

Pursuant to the authority contained in Section 512 of the Employee Retirement Income Security Act of 1974 (ERISA), 29 U.S.C. 1142, the 145th open meeting of the full Advisory Council on Employee Welfare and Pension Benefit Plans will be held on June 11, 2009.

The session will take place in Room S–2508, U.S. Department of Labor, 200 Constitution Avenue NW., Washington, DC 20210. The purpose of the open meeting, which will run from 1:30 p.m. to approximately 4:30 p.m., is to swear in the new members, introduce the Council Chair and Vice Chair, receive an update from the Employee Benefits Security Administration, and determine the topics to be addressed by the Council in 2009.

Organizations or members of the public wishing to submit a written statement may do so by submitting 25 copies on or before June 4, 2009 to Larry Good, Executive Secretary, ERISA Advisory Council, U.S. Department of Labor, Suite N–5623, 200 Constitution Avenue, NW., Washington, DC 20210. Statements may also be submitted electronically to *good.larry@dol.gov.* Statements received on or before June 4, 2009 will be included in the record of the meeting. Individuals or representatives of organizations wishing to address the Advisory Council should forward their requests to the Executive Secretary or telephone (202) 693–8668. Oral presentations will be limited to ten minutes, time permitting, but an extended statement may be submitted for the record. Individuals with disabilities who need special accommodations should contact Larry Good by June 4 at the address indicated.

Signed at Washington, DC this 20th day of May, 2009.

Michael L. Davis,

Deputy Assistant Secretary, Employee Benefits Security Administration.

[FR Doc. E9–12114 Filed 5–22–09; 8:45 am]

BILLING CODE 4510–29–P

LEGAL SERVICES CORPORATION

Sunshine Act Meeting of the Board of Directors; Amended Notice; Participant Dial-In Number Added to Notice

NOTICE: The Legal Services Corporation (LSC) is announcing an amendment to the notice of the Board of Directors meeting scheduled for Tuesday, May 26, 2009 via conference call. The Board of Directors meeting was announced in the **Federal Register** issue dated May 20, 2009, 74 FR 23748. The sole amendment to the notice is to add the Participant Dial-In Number. Other than adding the Participant Dial-In Number there is no other change to the announcement cited above.

TIME AND DATE: The Board of Directors of the Legal Services Corporation will meet on May 26, 2009 via conference call. The meeting will begin at 11 a.m. (EDT), and continue until conclusion of the Board's agenda.

LOCATION: 3333 K Street, NW., Washington, DC 20007, 3rd Floor Conference Room.

STATUS OF MEETING: Open. Directors will participate by telephone conference in such a manner as to enable interested members of the public to hear and identify all persons participating in the meeting. Members of the public may observe the meeting by joining participating staff at the location indicated above or calling 1–800–247–9979 (Conference ID# 99970441).

MATTERS TO BE CONSIDERED

1. Approval of the agenda.
2. Consider and act on Board of Directors' response to the Inspector General's Semiannual Report to Congress for the period of October 1, 2008 through March 31, 2009.
3. Consider and act on other business.
4. Public comment.

CONTACT PERSON FOR INFORMATION: Katherine Ward, Executive Assistant to the Vice President for Legal Affairs, at (202) 295–1500.

SPECIAL NEEDS: Upon request, meeting notices will be made available in alternate formats to accommodate visual and hearing impairments. Individuals who have a disability and need an accommodation to attend the meeting may notify Katherine Ward, at (202) 295–1500.

Dated: May 15, 2009.

Victor M. Fortuno,

Vice President for Legal Affairs, General Counsel & Corporate Secretary.

[FR Doc. E9–12297 Filed 5–21–09; 4:15 pm]

BILLING CODE 7050–01–P

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION

[Notice (09–043)]

NASA Advisory Council; Science Committee; Astrophysics Subcommittee; Meeting

AGENCY: National Aeronautics and Space Administration.

ACTION: Notice of meeting.

SUMMARY: The National Aeronautics and Space Administration (NASA) announces a meeting of the Astrophysics Subcommittee of the NASA Advisory Council (NAC). This Subcommittee reports to the Science Committee of the NAC. The Meeting will be held for the purpose of soliciting from the scientific community and other persons scientific and technical information relevant to program planning.

DATES: Tuesday, June 16, 2009, 10 a.m. to 5 p.m. and Wednesday, June 17, 2009, 10 a.m. to 4 p.m. Eastern Daylight Time.

ADDRESSES: NASA Headquarters, 300 E Street, SW., Room 3H46, Washington, DC 20546.

FOR FURTHER INFORMATION CONTACT: Ms. Marian Norris, Science Mission Directorate, NASA Headquarters, Washington, DC 20546, (202) 358–4452, fax (202) 358–4118, or *mnorris@nasa.gov.*

SUPPLEMENTARY INFORMATION: The meeting will be open to the public up to the capacity of the room. The agenda for the meeting includes the following topics:

—Astrophysics Division Overview and Fiscal Year 2010 Budget Request
—James Webb Space Telescope Update
—Stratospheric Observatory for Infrared Astronomy Update
—Hubble Space Telescope Post-Shuttle Mission 4 Update
—Update on Recommendation Items from Previous Astrophysics Subcommittee Meeting

It is imperative that the meeting be held on these dates to accommodate the scheduling priorities of the key participants. Attendees will be requested to sign a register and to comply with NASA security requirements, including the presentation of a valid picture ID, before receiving an access badge. Foreign nationals attending this meeting will be required to provide a copy of their passport, visa, or green card in addition to providing the following information no less than 7 working days prior to the meeting: Full name; gender; date/place of birth; citizenship; visa/green card information (number, type, expiration date); passport information (number, country, expiration date); employer/affiliation information (name of institution, address, country, telephone); title/position of attendee. To expedite admittance, attendees with U.S. citizenship can provide identifying information 3 working days in advance by contacting Marian Norris via e-mail at *mnorris@nasa.gov* or by telephone at (202) 358–4452.

Dated: May 18, 2009.

P. Diane Rausch,

Advisory Committee Management Officer, National Aeronautics and Space Administration.

[FR Doc. E9–12133 Filed 5–22–09; 8:45 am]

BILLING CODE 7510–13–P

NATIONAL FOUNDATION ON THE ARTS AND THE HUMANITIES

National Endowment for the Arts; Arts Advisory Panel

Pursuant to Section 10(a)(2) of the Federal Advisory Committee Act (Pub. L. 92–463), as amended, notice is hereby given that one meeting of the Arts Advisory Panel to the National Council on the Arts will be held by teleconference from the Nancy Hanks Center, 1100 Pennsylvania Avenue, NW., Washington, DC, 20506. This meeting, originally announced for May 22, 2009, had to be rescheduled on an emergency basis to review applications for funding under the American Recovery and Reinvestment Act of 2009 as follows (ending time is approximate): Learning in the Arts for Children and Youth (application review): May 28, 2009. This meeting, from 10 a.m. to 12:30 p.m., will be closed.

The closed portions of meetings are for the purpose of Panel review, discussion, evaluation, and recommendations on financial assistance under the National Foundation on the Arts and the Humanities Act of 1965, as amended, including information given in confidence to the agency. In accordance with the determination of the Chairman of February 28, 2008, these sessions will be closed to the public pursuant to subsection (c)(6) of section 552b of Title 5, United States Code.

Further information with reference to these meetings can be obtained from Ms. Kathy Plowitz-Worden, Office of Guidelines & Panel Operations, National Endowment for the Arts, Washington, DC 20506, or call 202/682–5691.

Dated: May 21, 2009.

Kathy Plowitz-Worden,

Panel Coordinator, Panel Operations, National Endowment for the Arts.

[FR Doc. E9–12294 Filed 5–22–09; 8:45 am]

BILLING CODE 7537–01–P

NUCLEAR REGULATORY COMMISSION

[NRC–2008–0122]

Draft Regulatory Guide: Issuance, availability; correction

AGENCY: Nuclear Regulatory Commission.

ACTION: Draft Regulatory Guide: Issuance, availability; correction.

SUMMARY: This document corrects a notice appearing in the **Federal Register** on May 18, 2009 (74 FR 23220), concerning the issuance of Draft Regulatory Guide 1237. This action is necessary to correct the spelling of the contact's first name, e-mail address and the comment receipt date.

FOR FURTHER INFORMATION CONTACT: Stephen F. LaVie, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, telephone (301) 415–1081 or e-mail to *Steve.LaVie@nrc.gov*.

SUPPLEMENTARY INFORMATION: On page 23220, in the third column, under **FOR FURTHER INFORMATION CONTACT**, the spelling of the first name of the contact is changed from ''Steven'' to read ''Stephen.'' The e-mail address is changed from ''*Steven.LaVie@nrc.gov*'' to read ''*Steve.LaVie@nrc.gov*.''

On page 23221, in the first column, third full paragraph, the spelling of the first name of the contact is changed from ''Steven'' to read ''Stephen.'' The e-mail address is changed from ''*Steven.LaVie@nrc.gov*'' to read ''*Steve.LaVie@nrc.gov*.''

On page 23221, in the first column, fourth full paragraph, the comment receipt date is changed from ''September 1, 2009'' to read ''August 3, 2009.''

Dated at Rockville, Maryland, this 18th day of May, 2009.

For the Nuclear Regulatory Commission.

R. A. Jervey,

Acting Chief, Regulatory Guide Development Branch, Division of Engineering, Office of Nuclear Regulatory Research.

[FR Doc. E9–12102 Filed 5–22–09; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[Docket Nos. 50–528, 50–529, 50–530; NRC–2009–0012]

Arizona Public Service Company; Notice of Intent To Prepare an Environmental Impact Statement and Conduct Scoping Process for Palo Verde Nuclear Generating Station, Units 1, 2, and 3

Arizona Public Service Company (APS) has submitted an application for renewal of Facility Operating License Nos. NPF–41, NPF–51, and NPF–74 for an additional 20 years of operation at the Palo Verde Nuclear Generating Station, Units 1, 2, and 3 (Palo Verde). Palo Verde is located in Maricopa County, Arizona, approximately 26 miles west of the Phoenix city limits.

The current operating licenses for Palo Verde expire on June 1, 2025, April 24, 2026, and November 25, 2027, for Units 1, 2, and 3, respectively. The application for renewal, dated December 11, 2008, and supplemented by letter dated April 14, 2009, was submitted pursuant to Title 10 of the *Code of Federal Regulations* (10 CFR) Part 54. A notice of receipt and availability of the application, which included the environmental report (ER), was published in the **Federal Register** on January 21, 2009 (74 FR 3655). A notice of acceptance for docketing of the application and opportunity for hearing regarding renewal of the facility operating license was published in the **Federal Register** on May 15, 2009 (74 FR 22978). The purpose of this notice is to inform the public that the U.S. Nuclear Regulatory Commission (NRC) will be preparing an environmental impact statement (EIS) related to the review of the license renewal application and to provide the public an opportunity to participate in the environmental scoping process, as defined in 10 CFR 51.29. In addition, as outlined in 36 CFR 800.8, ''Coordination with the National Environmental Policy Act,'' the NRC plans to coordinate compliance with Section 106 of the National Historic Preservation Act in meeting the requirements of the National Environmental Policy Act of 1969 (NEPA).

In accordance with 10 CFR 51.53(c) and 10 CFR 54.23, APS submitted the ER as part of the application. The ER was prepared pursuant to 10 CFR Part 51 and is publicly available at the NRC Public Document Room (PDR), located at One White Flint North, 11555 Rockville Pike, Rockville, Maryland 20852, or from the NRC's Agencywide Documents Access and Management System (ADAMS). The ADAMS Public Electronic Reading Room is accessible at *http://adamswebsearch.nrc.gov/dologin.htm.* The ADAMS accession number for the ER is ML083510615 (pp. 371–794) and the supplement is ML091130221. Persons who do not have access to ADAMS or who encounter problems in accessing the documents located in ADAMS, should contact the NRC's PDR reference staff by telephone at 1–800–397–4209, or 301–415–4737, or by e-mail at *pdr.resource@nrc.gov.* The ER may also be viewed on the Internet at *http://www.nrc.gov/reactors/operating/licensing/renewal/applications/palo-verde.html.* In addition, the ER is available for public inspection near the Palo Verde site at the Litchfield Park Branch Library, 101 West Wigwam Boulevard, Litchfield Park, Arizona 85340.

This notice advises the public that the NRC intends to gather the information necessary to prepare a plant-specific supplement to the Commission's ''Generic Environmental Impact Statement (GEIS) for License Renewal of Nuclear Plants,'' (NUREG–1437), related to the review of the application for renewal of the Palo Verde operating license for an additional 20 years. Possible alternatives to the proposed action (license renewal) include no action and reasonable alternative energy sources. The NRC is required by 10 CFR 51.95 to prepare a supplement to the GEIS in connection with the renewal of an operating license. This notice is being published in accordance with NEPA and the NRC's regulations found in 10 CFR Part 51.

The NRC will first conduct a scoping process for the supplement to the GEIS and, as soon as practicable thereafter, will prepare a draft supplement to the GEIS for public comment. Participation in the scoping process by members of the public and local, State, Tribal, and Federal government agencies is encouraged. The scoping process for the supplement to the GEIS will be used to accomplish the following:

a. Define the proposed action which is to be the subject of the supplement to the GEIS.

b. Determine the scope of the supplement to the GEIS and identify the significant issues to be analyzed in depth.

c. Identify and eliminate from detailed study those issues that are peripheral or that are not significant.

d. Identify any environmental assessments and other ElSs that are being or will be prepared that are related to, but are not part of, the scope of the supplement to the GEIS being considered.

e. Identify other environmental review and consultation requirements related to the proposed action.

f. Indicate the relationship between the timing of the preparation of the environmental analyses and the Commission's tentative planning and decision-making schedule.

g. Identify any cooperating agencies and, as appropriate, allocate assignments for preparation and schedules for completing the supplement to the GEIS to the NRC and any cooperating agencies.

h. Describe how the supplement to the GEIS will be prepared, and include any contractor assistance to be used.

The NRC invites the following entities to participate in scoping:

a. The applicant, APS.

b. Any Federal agency that has jurisdiction by law or special expertise with respect to any environmental impact involved, or that is authorized to develop and enforce relevant environmental standards.

c. Affected State and local government agencies, including those authorized to develop and enforce relevant environmental standards.

d. Any affected Indian tribe.

e. Any person who requests or has requested an opportunity to participate in the scoping process.

f. Any person who has petitioned or intends to petition for leave to intervene.

In accordance with 10 CFR 51.26, the scoping process for an EIS may include a public scoping meeting to help identify significant issues related to a proposed activity and to determine the scope of issues to be addressed in an EIS. The NRC has decided to hold public meetings for the Palo Verde license renewal supplement to the GEIS. The scoping meetings will be held on June 25, 2009, and there will be two sessions to accommodate interested parties. The first session will convene at 2 p.m. and will continue until 5 p.m., as necessary, and will be held at the Tonopah Valley High School, 38201 West Indian School Road, Tonopah, Arizona 85354. The second session will convene at 7 p.m. with a repeat of the overview portions of the meeting and will continue until 10 p.m., as necessary, and will be held at the Estrella Mountain Community College, 3000 North Dysart Road, Avondale, Arizona 85392. Both meetings will be transcribed and will include: (1) An overview by the NRC staff of the NEPA environmental review process, the proposed scope of the supplement to the GEIS, and the proposed review schedule; and (2) the opportunity for interested government agencies, organizations, and individuals to submit comments or suggestions on the environmental issues or the proposed scope of the supplement to the GEIS. Additionally, the NRC staff will host informal discussions one hour prior to the start of each session at the same location. No formal comments on the proposed scope of the supplement to the GEIS will be accepted during the informal discussions. To be considered, comments must be provided either at the transcribed public meetings or in writing, as discussed below. Persons may register to attend or present oral comments at the meetings on the scope of the NEPA review by contacting the NRC Project Manager, Lisa Regner, by telephone at 1–800–368–5642, extension 1906 or by e-mail at *Lisa.Regner@nrc.gov* no later than June 18, 2009. Members of the public may also register to speak at the meeting within 15 minutes of the start of each session. Individual oral comments may be limited by the time available, depending on the number of persons who register. Members of the public who have not registered may also have an opportunity to speak, if time permits. Public comments will be considered in the scoping process for the supplement to the GEIS. Ms. Regner will need to be contacted no later than June 18, 2009, if special equipment or accommodations are needed to attend or present information at the public meeting, so that the NRC staff can determine whether the request can be accommodated.

Members of the public may send written comments on the environmental scope of the Palo Verde license renewal review to: Chief, Rulemaking and Directives Branch, Division of Administrative Services, Office of Administration, Mailstop TWB 5B–01M, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, and should cite the publication date and page number of this **Federal Register** notice. To be considered in the scoping process, written comments should be postmarked by July 27, 2009. Electronic comments may be sent by e-mail to the NRC at *PaloVerde.EIS@nrc.gov,* and should be sent no later than July 27, 2009, to be considered in the scoping process. Comments will be available electronically and accessible through ADAMS at *http://adamswebsearch.nrc.gov/dologin.htm.*

Participation in the scoping process for the supplement to the GEIS does not entitle participants to become parties to the proceeding to which the supplement to the GEIS relates. Matters related to participation in any hearing are outside the scope of matters to be discussed at this public meeting.

At the conclusion of the scoping process, the NRC will prepare a concise summary of the determination and conclusions reached, including the significant issues identified, and will send a copy of the summary to each participant in the scoping process. The summary will also be available for inspection in ADAMS at *http://adamswebsearch.nrc.gov/dologin.htm.* The staff will then prepare and issue for comment the draft supplement to the GEIS, which will be the subject of separate notices and separate public meetings. Copies will be available for public inspection at the above-mentioned addresses, and one copy per request will be provided free of charge. After receipt and consideration of the comments, the NRC will prepare a final supplement to the GEIS, which will also be available for public inspection.

Information about the proposed action, the supplement to the GEIS, and the scoping process may be obtained from Ms. Regner at the aforementioned telephone number or e-mail address.

Dated at Rockville, Maryland, this 18th day of May, 2009.

For the Nuclear Regulatory Commission.

David J. Wrona,

Chief, Projects Branch 2, Division of License Renewal, Office of Nuclear Reactor Regulation.

[FR Doc. E9–12098 Filed 5–22–09; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[Docket No. 70–1257; NRC–2009–0147]

Notice of Renewal of Special Nuclear Material License No. SNM–1227 [AREVA NP, Inc., Richland, WA]

AGENCY: Nuclear Regulatory Commission.

ACTION: Notice of renewal of license.

FOR FURTHER INFORMATION CONTACT: Rafael L. Rodriguez, Project Manager, Fuel Manufacturing Branch, Division of Fuel Cycle Safety and Safeguards, Office of Nuclear Material Safety and Safeguards, U.S. Nuclear Regulatory Commission, Rockville, MD 20852. *Telephone:* (301) 492–3111; *Fax number:* (301) 492–3363; *E-mail: Rafael.Rodriguez@nrc.gov*.

SUPPLEMENTARY INFORMATION:

I. Introduction

By letter dated October 24, 2006, AREVA NP, Inc. (AREVA) requested the renewal of Special Nuclear Material License No. SNM–1227. Pursuant to Title 10 of the *Code of Federal Regulations* (10 CFR), Section 2.106, the U.S. Nuclear Regulatory Commission (NRC) is providing notice that Special Nuclear Material License No. SNM–1227, which authorizes AREVA to possess and process enriched uranium up to a maximum of five weight percent uranium-235, for the manufacture of fuel assemblies for commercial nuclear power plants (both pressurized water reactors and boiling water reactors) at its fuel fabrication facility in Richland, Washington, has been renewed for a period of 40 years. AREVA's request for the proposed renewed license was previously noticed, and an opportunity to request a hearing provided, in the **Federal Register** on March 15, 2007 (72 FR 12202). A Notice of Availability of Environmental Assessment and Finding of No Significant Impact has been noticed in the **Federal Register** on April 3, 2009 (74 FR 15312).

This license complies with the standards and requirements of the Atomic Energy Act of 1954, as amended, and NRC's rules and regulations as set forth in 10 CFR Chapter 1. Accordingly, this license was renewed on April 24, 2009, and is effective immediately.

II. Further Information

The NRC has prepared a Safety Evaluation Report (SER) that documents the information that was reviewed and the NRC's conclusion. In accordance with 10 CFR 2.390 of the NRC's ''Rules of Practice,'' details with respect to this action, including the SER and accompanying documentation included in the license package, are available electronically at the NRC's Electronic Reading Room at *http://www.nrc.gov/reading-rm/adams.html*. From this site, you can access the NRC's Agencywide Document Access and Management System (ADAMS), which provides text and image files of NRC's public documents. The ADAMS accession numbers for the documents related to this notice are:

(1) October 24, 2006, License Renewal Application and Environmental Report: ML063110082.

(2) December 13, 2006, Supplement to License Renewal Application: ML063530128.

(3) December 10, 2008, Revised License Renewal Application: ML090400202.

(4) SER in Support of License Renewal Application (Public Version): ML090760702.

(5) Special Nuclear Materials License No. SNM–1227 (Public Version): ML090680579.

If you do not have access to ADAMS, or if there are problems in accessing the documents located in ADAMS, contact the NRC Public Document Room (PDR) Reference staff at 1–800–397–4209, 301–415–4737 or by e-mail to *PDR.Resource@nrc.gov*.

These documents may also be viewed electronically on the public computers located at the NRC's Public Document Room (PDR), O–1 F21, One White Flint North, 11555 Rockville Pike, Rockville, MD 20852. The PDR reproduction contractor will copy documents for a fee.

Dated at Rockville, MD this 18th day of May, 2009.

For the Nuclear Regulatory Commission.

Peter J. Habighorst,

Chief, Fuel Manufacturing Branch, Division of Fuel Cycle Safety and Safeguards, Office of Nuclear Material Safety and Safeguards.

[FR Doc. E9–12096 Filed 5–22–09; 8:45 am]

BILLING CODE 7590–01–P

OVERSEAS PRIVATE INVESTMENT CORPORATION

Second Notice: Federal Register; Submission for OMB Review

AGENCY: Overseas Private Investment Corporation (OPIC).

ACTION: Request for comments.

SUMMARY: Under the provision of the Paperwork Reduction Act (44 U.S.C. Chapter 35), agencies are required to publish a Notice in the **Federal Register** notifying the public, that the Agency is revising an information collection request for OMB review, approval, and request public review and comment on the submission. Comments are being solicited on the need for the information; the accuracy of the Agency's burden estimate; the quality, practical utility and clarity of the information to be collected; and ways to minimize the reporting burden, including automated collection techniques by using other forms of technology. The proposed form under review is summarized below.

DATES: Comments must be received within 30 calendar days of publication of this Notice.

ADDRESSES: Copies of the subject form and the request for review prepared for submission to OMB may be obtained from the Agency submitting officer. Comments on the form should be submitted to the Agency Submitting Officer.

FOR FURTHER INFORMATION CONTACT: OPIC Agency Submitting Officer: Essie S. Bryant, Records Management Officer, Overseas Private Investment Corporation, 1100 New York Avenue, NW., Washington, DC 20527; 202–336–8563.

OMB Contact: Office of Information and Regulatory Affairs, U.S. Office of Information and Regulator Affairs, Office of Management and Budget, Attention: Ms. Wendy Liberante, 725 17th Street, Room 10102, NW., Washington, DC 20503; (202) 395–3647.

Summary Form Under Review

Type of Request: Reinstatement, with changes, of a previously approved collection for which approval is expiring.

Title: Sponsor Disclosure Report.

Form Number: OPIC–129.

Frequency of Use: Once per major sponsor, per project.

Type of Respondents: Business or other institutions.

Standard Industrial Classification Codes: All.

Description of Affected Public: U.S. Companies sponsoring projects overseas.

Reporting Hours: 5 hours per project.

Number of Responses: 300 per year.

Federal Cost: $66,000 per year.

Authority for Information Collection: Sections 231, 234(b), and (c) of the Foreign Assistance Act of 1961, as amended.

Abstract (Needs and Uses): The OPIC 129 form is the principal document used by OPIC to determine the investor's and project's eligibility, assess the environmental impact and developmental effects of the project, measure the economic effects for the United States and the host country economy, and collect information for underwriting analysis.

Dated: May 19, 2009.

Genevieve Stubbs,

Senior Administrative & FOIA Counsel, Department of Legal Affairs.

[FR Doc. E9–12097 Filed 5–22–09; 8:45 am]

BILLING CODE M

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 July 27, 2009.

ADDRESSES: Send all comments regarding whether these information collections are 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 Carol Fendler, Systems Accountant, Office of Investment, Small Business Administration, 409 3rd Street, 6th Floor, Washington, DC 20416.

FOR FURTHER INFORMATION CONTACT: Carol Fendler, Systems Accountant, Office of Investments, 202–205–7559, *carol.fendler@sba.gov*, Curtis B. Rich, Management Analyst, 202–205–7030, *curtis.rich@sba.gov*.

SUPPLEMENTARY INFORMATION: This form is used by SBA examiners to obtain information about financing provided by small business investment companies (SBICs). This information which is collected directly from the financial small businesses, provides independent confirmation of information respond to SBA by SBICs, as additional information not reported by SBICs.

Title: ''Request for Information Concerning Portfolio Financing.''

Description of Respondents: SBIC Investment Companies.

Form Number: 857.

Annual Responses: 2,160.

Annual Burden: 2,160.

SUPPLEMENTARY INFORMATION:

This form is used by SBA examiners to obtain information about assets of Small Business investment companies (SBICs) that are held in accounts at financial institutions, and about SBIC borrowings from financial institutions. This information, which is collected directly from the financial institutions, provides independent confirmation of asset and liability figures reported to SBA by SBICs as well as supplemental information used to evaluate regulatory compliance and financial condition.

Title: ''Financial Institution Confirmation Form.''

Description of Respondents: SBIC Investment Companies.

Form Number: 860.

Annual Responses: 1,500.

Annual Burden: 750.

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 Rachel Newman Karton, Program Analyst, Office of Small Business Development Centers, Small Business Administration, 409 3rd Street, 6th Floor, Washington, DC 20416.

FOR FURTHER INFORMATION CONTACT: Rachel Newman Karton, Program Analyst, Office of Small Business Development Centers, 202–619–1816, *rachel.newman@sba.gov*, Curtis B. Rich, Management Analyst, 202–205–7030, *curtis.rich@sba.gov*.

SUPPLEMENTARY INFORMATION:

This form is used to measure the quality and impact of counseling provided by SBA's resource partner the Small Business Development Centers (SBDCs). The SBDC State Director and the Project Officer reviews the forms to determine if the client received satisfactory counseling services.

Title: ''SBA Counseling Evaluation.''

Description of Respondents: Small Business Clients.

Form Number: 1419.

Annual Responses: 15,000.

Annual Burden: 2,550.

Jacqueline White,

Chief, Administrative Information Branch.

[FR Doc. E9–12134 Filed 5–22–09; 8:45 am]

BILLING CODE 8025–01–P

SECURITIES AND EXCHANGE COMMISSION

[File No. 500–1]

In the Matter of Nanosignal Corp., Inc. (n/k/a Nano Global, Inc.), National Micronetics, Inc., NetVoice Technologies Corp., Network Access Solutions Corp., Network Plus Corp., The New Anaconda Co., New York Regional Rail Corp., NewCom International, Inc. (n/k/a Sino Express Travel Ltd.), NewKidCo International, Inc., NexGen Vision, Inc., and Noel Group, Inc.; Order of Suspension of Trading

May 21, 2009.

It appears to the Securities and Exchange Commission that there is a lack of current and accurate information concerning the securities of Nanosignal Corp., Inc. (n/k/a Nano Global, Inc.) because it has not filed any periodic reports since the period ended September 30, 2004.

It appears to the Securities and Exchange Commission that there is a lack of current and accurate information concerning the securities of National Micronetics, Inc. because it has not filed any periodic reports since the period ended March 31, 2000.

It appears to the Securities and Exchange Commission that there is a lack of current and accurate information concerning the securities of NetVoice Technologies Corp. because it has not filed any periodic reports since the period ended June 30, 2001.

It appears to the Securities and Exchange Commission that there is a lack of current and accurate information concerning the securities of Network Access Solutions Corp. because it has not filed any periodic reports since the period ended March 31, 2002.

It appears to the Securities and Exchange Commission that there is a lack of current and accurate information concerning the securities of Network Plus Corp. because it has not filed any periodic reports since the period ended September 30, 2001.

It appears to the Securities and Exchange Commission that there is a lack of current and accurate information concerning the securities of The New Anaconda Co. because it has not filed any periodic reports since the period ended December 31, 2000.

It appears to the Securities and Exchange Commission that there is a lack of current and accurate information concerning the securities of New York Regional Rail Corp. because it has not filed any periodic reports since the period ended September 30, 2005.

It appears to the Securities and Exchange Commission that there is a lack of current and accurate information concerning the securities of NewCom International, Inc. (n/k/a Sino Express Travel Ltd.) because it has not filed any periodic reports since the period ended September 30, 2003.

It appears to the Securities and Exchange Commission that there is a lack of current and accurate information concerning the securities of NewKidCo International, Inc. because it has not filed any periodic reports since the period ended December 31, 2001.

It appears to the Securities and Exchange Commission that there is a lack of current and accurate information concerning the securities of NexGen Vision, Inc. because it has not filed any periodic reports since the period ended June 30, 2003.

It appears to the Securities and Exchange Commission that there is a lack of current and accurate information concerning the securities of Noel Group, Inc. because it has not filed any periodic reports since the period ended June 30, 1999.

The Commission is of the opinion that the public interest and the protection of investors require a suspension of trading in the securities of the above-listed companies.

Therefore, it is ordered, pursuant to Section 12(k) of the Securities Exchange Act of 1934, that trading in the securities of the above-listed companies is suspended for the period from 9:30 a.m. EDT on May 21, 2009, through 11:59 p.m. EDT on June 4, 2009.

By the Commission.

Jill M. Peterson,

Assistant Secretary.

[FR Doc. E9–12253 Filed 5–21–09; 4:15 pm]

BILLING CODE 8010–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–59935; File No. SR–CBOE–2009–028]

Self-Regulatory Organizations; Chicago Board Options Exchange, Incorporated; Notice of Filing of Proposed Rule Change Relating to Rebating Member Dues for Certain Members

May 18, 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 May 6, 2009, Chicago Board Options Exchange, Incorporated (''CBOE'' 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 CBOE. 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

Chicago Board Options Exchange, Incorporated (''CBOE'' or ''Exchange'') proposes to amend its Fees Schedule to rebate member dues for certain members. The text of the proposed rule change is available on the Exchange's Web site (*http://www.cboe.org/legal*), at the Exchange's Office of the Secretary and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, CBOE 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. CBOE has prepared summaries, set forth in sections A, B, and C below, of the most significant parts of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

CBOE assesses dues with respect to every membership (unless a member is assessed the Hybrid Electronic Quoting Fee, in which case the member does not pay member dues).[4] Under Rule 3.17(c), the membership lease agreement between a lessor member and a lessee member designates who is responsible for Exchange dues, fees and other charges. Typically, leases provide that the lessee is responsible for dues and therefore lessors do not pay dues.

Under the lessor compensation component of the Interim Trading Permit (''ITP'') program, the Exchange compensates a lessor for an ''open lease'' while the ITP program is active and ITPs are outstanding.[5] The goal of this component of the ITP program is to put such a lessor in a similar position as if the lessor's membership was leased. This goal would be frustrated if the lessor is charged dues because the lessor would be subject to an obligation the lessor would not otherwise be subject to if the lessor's membership was leased.

Consistent with this goal, the Exchange will waive member dues for a lessor member for any month in which the lessor receives a payment from the Exchange for an open lease under the ITP program. This waiver became effective on May 1, 2009, pursuant to a

[1] 15 U.S.C. 78s(b)(1).

[2] 15 U.S.C. 78a.

[3] 17 CFR 240.19b–4.

[4] Member dues are $450 per month. *See* CBOE Fees Schedule, Section 10.

[5] The ITP program is a program pursuant to which the Exchange has the authority to issue up to 50 ITPs. The ITP program is governed by CBOE Rule 3.27. The lessor compensation component of the ITP program is described in CBOE Rule 3.27(d). An ''open lease'' is defined in Rule 3.27(d) as a transferable Exchange membership available for lease.

previous rule change that was filed by the Exchange for immediate effectiveness.[6] The Exchange now proposes to rebate dues to any lessor member who received such a payment from the Exchange during the period August 1, 2008,[7] through April 30, 2009.

2. Statutory Basis

The Exchange believes the proposed rule change is consistent with Section 6(b) of the Securities Exchange Act of 1934 (''Act''),[8] in general, and furthers the objectives of Section 6(b)(4) [9] of the Act in particular, in that it is designed to provide for the equitable allocation of reasonable dues, fees, and other charges among its members and other persons using its facilities. The Exchange believes the proposed rebate of member dues is equitable and reasonable in that it would help the Exchange place a lessor member who received compensation from the Exchange for an open lease under the ITP program prior to May 1, 2009, in a similar position as if the lessor's membership had been leased, consistent with Exchange Rule 3.27(d).

B. Self-Regulatory Organization's Statement on Burden on Competition

CBOE does not believe that the proposed rule change will impose any burden on competition that is not necessary or appropriate in furtherance of 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

Within 35 days of the date of publication of this notice in the **Federal Register** or within such longer period (i) as the Commission may designate up to 90 days of such date if it finds such longer period to be appropriate and publishes its reasons for so finding or (ii) as to which the self-regulatory organization consents, the Commission will:

(A) By order approve such proposed rule change, or

(B) Institute proceedings to determine whether the proposed rule change should be disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

• Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or

• Send an e-mail to *rule-comments@sec.gov.* Please include File Number SR–CBOE–2009–028 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–CBOE–2009–028. 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 the filing will also be available for inspection and copying at the principal office of the self-regulatory organization. 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–CBOE–2009–028 and should be submitted on or before June 16, 2009.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[10]

Florence E. Harmon,

Deputy Secretary.

[FR Doc. E9–12090 Filed 5–22–09; 8:45 am]

BILLING CODE 8010–01–P

[6] *See* SR–CBOE–2009–027.

[7] The ITP program was approved by the Commission on July 17, 2008. *See* Securities Exchange Act Release No. 58178 (July 17, 2008), 73 FR 42634 (July 22, 2008).

[8] 15 U.S.C. 78f(b).

[9] 15 U.S.C. 78f(b)(4).

[10] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 59933; File No. SR–NASDAQ–2009–028]

Self-Regulatory Organizations; The NASDAQ Stock Market LLC; Order Approving Proposed Rule Change to Reduce Fees for NASDAQ Basic Data Feeds

May 15, 2009.

I. Introduction

On March 27, 2009, The NASDAQ Stock Market LLC (''NASDAQ'' or ''Exchange'') filed with the Securities and Exchange Commission (''Commission''), pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'') [1] and Rule 19b–4 thereunder,[2] a proposed rule change to reduce the fees for NASDAQ Basic, a real time data feed combining both NASDAQ's Best Bid and Offer (''QBBO'') and the NASDAQ Last Sale. The proposed rule change was published for comment in the **Federal Register** on April 14, 2009.[3] The Commission received no comment letters on the proposal. This order approves the proposed rule change.

II. Description of the Proposal

NASDAQ Basic is a ''Level 1'' data product containing quotation information from the NASDAQ Market Center and last sale data from the NASDAQ Market Center. NASDAQ Basic was approved on March 16, 2009,[4] as a pilot program and includes fees for usage and distribution of the data. NASDAQ Basic is available in three forms, NASDAQ Basic for NASDAQ, NASDAQ Basic for NYSE, and NASDAQ Basic for Alternext. NASDAQ Basic is designed to meet the needs of current and prospective subscribers that do not need or are unwilling to pay for the consolidated data provided by the consolidated Level 1 products.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 59712 (April 6, 2009), 74 FR 17273.

[4] *See* Securities Exchange Act Release No. 59582 (March 16, 2009) 74 FR 12423 (March 24, 2009) (SR–NASDAQ–2008–102) (''Pilot Approval Order'').

NASDAQ assesses a monthly fee for distributors of NASDAQ Basic in addition to applicable monthly per user fees. Currently, each Distributor of NASDAQ Basic for NASDAQ-listed stocks currently pays a monthly fee of $1,500 for either internal or external distribution, each Distributor of NASDAQ Basic for NYSE-listed stocks pays a monthly fee of $250 for internal distribution or $625 for external distribution, and each Distributor of NASDAQ Basic for Alternext-listed stocks pays a monthly fee of $250 for internal distribution or $625 for external distribution. In addition, each Distributor that receives Direct Access to the NASDAQ Basic pays a monthly fee of $2,000 for NASDAQ-listed stocks, $1,000 for NYSE-listed stocks, and $1,000 for Alternext-listed stocks.

NASDAQ proposes to reduce the distribution fees for NASDAQ Basic. First, NASDAQ proposes to make all three feeds available for a single monthly Distributor Fee of $1,500, rather than add separate fees for NYSE- and Alternext-listed securities. Second, NASDAQ proposes to eliminate the fee for Direct Access to NASDAQ Basic, currently set forth in Rule 7047(b). Finally, NASDAQ proposes to credit each Distributor of NASDAQ Basic up to $1,500 per month based upon that Distributor's monthly usage fees. For example, a Distributor that reports $1,500 or more of monthly usage of NASDAQ Basic will pay no net Distributor Fee, whereas a Distributor that reports $1,000 of monthly usage will pay a net of $500 for the Distributor Fee.

III. Discussion and Commission Findings

The Commission finds that the proposed rule change is consistent with the requirements of the Act and the rules and regulations thereunder applicable to a national securities exchange.[5] In particular, it is consistent with Section 6(b)(4) of the Act,[6] which requires that the rules of a national securities exchange provide for the equitable allocation of reasonable dues, fees, and other charges among its members and issuers and other parties using its facilities, and Section 6(b)(5) of the Act,[7] which requires, among other things, that the rules of a national securities exchange be designed to promote just and equitable principles of trade, to remove impediments to and perfect the mechanism of a free and open market and a national market system and, in general, to protect investors and the public interest, and not be designed to permit unfair discrimination between customers, issuers, brokers, or dealers.

The Commission also finds that the proposed rule change is consistent with the provisions of Section 6(b)(8) of the Act,[8] which requires that the rules of an exchange not impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act. Finally, the Commission finds that the proposed rule change is consistent with Rule 603(a) of Regulation NMS,[9] adopted under Section 11A(c)(1) of the Act, which requires an exclusive processor that distributes information with respect to quotations for or transactions in an NMS stock to do so on terms that are fair and reasonable and that are not unreasonably discriminatory.[10]

This proposal would reduce the distribution fees for NASDAQ Basic by charging a single monthly Distributor Fee of $1,500 for all three NASDAQ Basic feeds, eliminating the fee for Direct Access to NASDAQ Basic, and providing a credit to each Distributor of NASDAQ Basic up to $1,500 per month based upon that Distributor's monthly usage fees. The Commission has reviewed the proposal using the approach set forth in the NYSE Arca Order for non-core market data fees.[11] The Commission recently found that NASDAQ was subject to competitive forces in setting fees for NASAQ Basic in the Pilot Approval Order.[12] There are a variety of alternative sources of information that impose significant competitive pressures on NASDAQ in setting the terms for distributing NASDAQ Basic. The Commission believes that the availability of those alternatives, as well as NASDAQ's compelling need to attract order flow, imposed significant competitive pressure on NASDAQ to act equitably, fairly, and reasonably in setting the terms of its proposal.

Because NASDAQ was subject to significant competitive forces in setting the terms of the proposal, the Commission will approve the proposal in the absence of a substantial countervailing basis to find that its terms nevertheless fail to meet an applicable requirement of the Act or the rules thereunder. An analysis of the proposal does not provide such a basis.

IV. Conclusion

It is therefore ordered, pursuant to Section 19(b)(2) of the Act,[13] that the proposed rule change (SR–NASDAQ–2009–028), be, and it hereby is, approved.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[14]

Florence E. Harmon,

Deputy Secretary.

[FR Doc. E9–12143 Filed 5–22–09; 8:45 am]

BILLING CODE 8010–01–P

[5] In approving this proposed rule change, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

[6] 15 U.S.C. 78f(b)(4).

[7] 15 U.S.C. 78f(b)(5).

[8] 15 U.S.C. 78f(b)(6).

[9] 17 CFR 242.603(a).

[10] NASDAQ is an exclusive processor of NASDAQ Basic under Section 3(a)(22)(B) of the Act, 15 U.S.C. 78c(a)(22)(B), which defines an exclusive processor as, among other things, an exchange that distributes information with respect to quotations or transactions on an exclusive basis on its own behalf.

[11] *See* Securities Exchange Act Release No. 59039 (December 2, 2008), 73 FR 74770 (December 9, 2008) (SR–NYSEArca–2006–21) (''NYSE Arca Order''). In the NYSE Arca Order, the Commission describes the competitive factors that apply to non-core market data products. The Commission hereby incorporates by reference the data and analysis from the NYSE Arca Order into this order.

[12] *See* Pilot Approval Order, *supra* note 4.

[13] 15 U.S.C. 78s(b)(2).

[14] 17 CFR 200.30–3(a)(12).

DEPARTMENT OF STATE

[Public Notice: 6632]

Title: 60-Day Notice of Proposed Information Collection: Form DS–3097, Exchange Visitor Program Annual Report, and OMB Control Number 1405–0151

ACTION: Notice of request for public comments.

SUMMARY: The Department of State is seeking Office of Management and Budget (OMB) approval for the information collection described below. The purpose of this notice is to allow 60 days for public comment in the **Federal Register** preceding submission to OMB. We are conducting this process in accordance with the Paperwork Reduction Act of 1995.

- *Title of Information Collection:* Exchange Visitor Program Annual Report.
- *OMB Control Number:* 1405–0151.
- *Type of Request:* Revision of a Currently Approved Collection.
- *Originating Office:* Bureau of Educational and Cultural Affairs, Office of Private Sector Exchange, ECA/EC.
- *Form Number:* Form DS–3097.
- *Respondents:* Designated J–1 program sponsors.
- *Estimated Number of Respondents*: 1,460.
- *Estimated Number of Responses:* 1,460 annually.

• *Average Hours Per Response:* 1 hour.
• *Total Estimated Burden:* 1,460 hours.
• *Frequency:* Annually.
• *Obligation to Respond:* Mandatory.

DATES: The Department will accept comments from the public up to 60 days from May 26, 2009.

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

• *E-mail: jexchanges@state.gov.* You must include the DS form number and RIN in the subject line of your message.
• *Mail (paper, disk, or CD–ROM submissions):* U.S. Department of State, Office of Exchange Coordination and Designation, SA–44, 301 4th Street, SW., Room 734, Washington, DC 20547.
• *Fax:* 202–203–5087.

Persons with access to the Internet may also view this notice and provide comments by going to the regulations.gov Web site at: *http://www.regulations.gov/index.cfm.* You must include the DS form number, information collection title, and OMB control number in any correspondence.

FOR FURTHER INFORMATION CONTACT: Direct requests for additional information regarding the collection listed in this notice, including requests for copies of the proposed information collection and supporting documents, to Stanley S. Colvin, Deputy Assistant Secretary, Office of Private Sector Exchange, U.S. Department of State, SA–44, 301 4th Street, SW., Room 734, Washington, DC 20547; or e-mail at *jexchanges@state.gov.*

SUPPLEMENTARY INFORMATION:

We are soliciting public comments to permit the Department to:

• Evaluate whether the proposed information collection is necessary for the proper performance of our functions.
• Evaluate the accuracy of our estimate of the burden of the proposed collection, including the validity of the methodology and assumptions used.
• Enhance the quality, utility, and clarity of the information to be collected.
• Minimize the reporting burden on those who are to respond, including the use of automated collection techniques or other forms of technology.

Abstract of Proposed Collection

Annual reports from designated program sponsors assist the Department in oversight and administration of the J–1 visa program. The reports provide statistical data on the number of exchange participants an organization sponsored per category of exchange. The reports also provide a summary of the activities in which exchange visitors were engaged and an evaluation of program effectiveness. Program sponsors include government agencies, academic institutions, and private sector not-for-profit and for-profit entities.

Methodology

Annual reports are completed through the Student and Exchange Visitor Information System (SEVIS) and then printed and signed by a sponsor official, and sent to the Department by mail or fax. The Department is currently working with the Department of Homeland Security to expand SEVIS functions and enable the collection of electronic signatures. Annual reports will be submitted to the Department electronically as soon as the mechanism for doing so is approved and in place.

Dated: May 14, 2009.

Stanley S. Colvin,

Deputy Assistant Secretary for Private Sector Exchange, Bureau of Educational and Cultural Exchange, Department of State.

[FR Doc. E9–12147 Filed 5–22–09; 8:45 am]

BILLING CODE 4710–05–P

DEPARTMENT OF STATE

[Public Notice 6633]

In the Matter of the Review of the Designation of Abu Nidal Organization Movement (ANO) and Palestinian Liberation Front—Abu Abbas Faction (PLF) and All Designated Aliases, as Foreign Terrorist Organizations Pursuant to Section 219 of the Immigration and Nationality Act, as Amended

Based upon a review of the Administrative Record assembled in this matter pursuant to Section 219(a)(4)(C) of the Immigration and Nationality Act, as amended (8 U.S.C. 1189(a)(4)(C)) (''INA''), and in consultation with the Attorney General and the Secretary of the Treasury, I conclude that the circumstances that were the basis for the 2003 re-designation of the aforementioned organizations as foreign terrorist organizations have not changed in such a manner as to warrant revocation of the designation and that the national security of the United States does not warrant a revocation of the designations.

Therefore, I hereby determine that the designations of the aforementioned organizations as foreign terrorist organizations, pursuant to Section 219 of the INA (8 U.S.C. 1189), shall be maintained.

This determination shall be published in the **Federal Register**.

Dated: May 13 2009.

James B. Steinberg,

Deputy Secretary of State, Department of State.

[FR Doc. E9–12145 Filed 5–22–09; 8:45 am]

BILLING CODE 4710–10–P

DEPARTMENT OF STATE

[Public Notice 6631]

State–24, Medical Records

SUMMARY: Notice is hereby given that the Department of State proposes to alter an existing system of records, Medical Records, State–24, pursuant to the provisions of the Privacy Act of 1974, as amended (5 U.S.C. 552a) and Office of Management and Budget Circular No. A–130, Appendix I. The Department's report was filed with the Office of Management and Budget on May 18, 2009.

It is proposed that the current system will retain the name ''Medical Records.'' It is also proposed that due to the expanded scope of the current system, the altered system description will include revisions and/or additions to the following sections: Categories of Individuals Covered by the Systems, Categories of Records in the System, Purpose, Safeguards and Retrievability.

Any persons interested in commenting on the altered system of records may do so by submitting comments in writing to Margaret P. Grafeld, Director; Office of Information Programs and Services; A/GIS/IPS; Department of State, SA–2; 515 22nd Street, Washington, DC 20522–8001. This system of records will be effective 40 days from the date of publication, unless we receive comments that will result in a contrary determination.

The altered system description, ''Medical Records, State–24,'' will read as set forth below.

Dated: May 18, 2009.

Steven J. Rodriguez,

Deputy Assistant Secretary of Operations, Bureau of Administration, Department of State.

STATE–24

SYSTEM NAME:

Medical Records.

SYSTEM LOCATION:

Department of State, Office of Medical Services, 2401 E Street, NW., Washington, DC 20522, and Health Units at Overseas Posts.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

U.S. Government employees, family members, and any other individuals eligible to participate in the health care program of the U.S. Department of State as authorized by either section 904 of the Foreign Service Act of 1980 (22 U.S.C. 4084) or other legal authority.

CATEGORIES OF RECORDS IN THE SYSTEM:

Includes name, social security number, date of birth, address to include email and phone number; reports of medical examinations and related documents; reports of treatments and other health services rendered to individuals; narrative summaries of hospital treatments; personal medical histories; reports of on-the-job injuries or illnesses; and reports on medical evacuation, and/or any other types of individually identifiable health information generated or used in the course of conducting ''health care operations'' as this term is defined at 45 CFR 164.501. This system includes records that contain ''protected health information'' as this term is defined at 45 CFR 164.501, and accordingly, does not include records maintained by the Department of State and/or other employers in their capacity as employers. This system also includes certain records maintained as part of the Department's Employee Assistance Program pursuant to 5 CFR Part 792.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

22 U.S.C. 4084, 42 U.S.C. 290dd–1, Public Law 99–570 §§ 7361–7362; 5 CFR Part 792.

PURPOSE:

The information contained in these records is used to administer the Department of State's medical program. These records are utilized and reviewed by medical and administrative personnel of the Office of Medical Services (MED) in providing health care to the individuals eligible to participate in the health care program.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND THE PURPOSES OF SUCH USES:

Routine use of information from these files includes any use permitted by the Health Insurance Portability and Accountability Act (HIPAA) Privacy Rule at 45 CFR Part 164 for which no authorization or opportunity to agree or object is required by the subject of the information. Specifically, we may disclose the information:

—To a ''business associate,'' as that term is defined at 45 CFR 160.103; to another health care provider; or to a group health plan or health insurance issuer or Health Maintenance Organization for purposes of carrying out treatment, payment or health care operations;

—To a parent, guardian or other person acting *in loco parentis* with respect to the subject of the information;

—To a health oversight agency or public health authority authorized by law to investigate or otherwise oversee the relevant conduct or conditions of the Department of State's medical program, or for such oversight activities as audits; civil, administrative, or criminal proceedings or actions; inspections; licensure or disciplinary actions;

—To a public health authority (domestic or foreign) that is authorized by law to collect or receive protected health information for the purpose of preventing or controlling disease, injury, or disability, including, but not limited to, the reporting of disease, injury, vital events such as birth or death, and the conduct of public health surveillance, public health investigations, and public health interventions;

—To the U.S. Department of Health and Human Services (HHS), when required by the Secretary of HHS in order to investigate or determine compliance with the HIPAA;

—To a public health authority or other appropriate government authority (domestic or foreign) authorized by law to receive reports of child abuse or neglect;

—To a person subject to the jurisdiction of the Food and Drug Administration (FDA) with respect to an FDA-regulated product or activity for which that person has responsibility, for the purpose of activities related to the quality, safety or effectiveness of such FDA-regulated product or activity;

—To a person who may have been exposed to a communicable disease or may otherwise be at risk of contracting or spreading a disease or condition, to the extent MED is authorized by law to notify such person as necessary in the conduct of a public health intervention or investigation;

—To a government authority (domestic or foreign), including a social service or protective services agency, authorized by law to receive reports of abuse, neglect or domestic violence, (1) To the extent such a disclosure is required by law; (2) where in the exercise of professional judgment, the disclosure is necessary to prevent serious harm to the individual or other potential victims; or (3) where, if the subject of the information is incapacitated, a law enforcement, or other public official authorized to receive the report, represents that the information sought is not intended to be used against the individual and that an immediate enforcement activity that depends upon the disclosure would be adversely affected by waiting until the individual is able to agree to the disclosure;

—In the course of any judicial or administrative proceeding in response to an order of a court or administrative tribunal;

—To a law enforcement official (1) As required by law or in compliance with a court order or court-ordered warrant, or a subpoena or summons issued by a judicial officer, or a grand jury subpoena, or an administrative request, including an administrative subpoena or summons; (2) in response to a request for the purposes of identifying or locating a suspect, fugitive, material witness or missing person; in response to a request for such information about an individual who is or is suspected to be a victim of a crime; (3) where it is believed that in good faith that such information constitutes evidence of criminal conduct; or (4) in response to an emergency, where it is believed such disclosure is necessary to alert law enforcement to the commission and nature of a crime, the location of such crime or of the victim(s) of such crime, and the identity, description and location of the perpetrator of such crime;

—As necessary in order to prevent or lessen a serious and imminent threat to the health or safety of a person or the public, to a person or persons reasonably able to prevent or lessen the threat, including the target of the threat;

—To authorized federal officials for the conduct of lawful intelligence, counter-intelligence, and other national security activities authorized by the National Security Act (50 U.S.C. 401, *et seq.*) and implementing authority (*e.g.*, Executive Order 12333);

—To authorized federal officials for the provision of protective services to the President or other persons authorized by 18 U.S.C. 3056, or to foreign heads of state or other persons authorized by 22 U.S.C. 2709(a)(3), or for the conduct of investigations authorized by 18 U.S.C. 871 and 879.

—To make medical suitability determinations and disclose whether or not an individual is determined to be medically suitable to the officials in the Department of State who need access to such information (1) For the purposes of a national security clearance conducted pursuant to Executive Orders 10450 and 12698; (2) as necessary to determine worldwide availability, suitability for particular assignments, suitability for mandatory service abroad under sections 101(a)(4) and 504 of the Foreign Service Act; or (3) for a family to accompany a Foreign Service member abroad, consistent with section 101(b)(5) and 904 of the Foreign Service Act.

—To a correctional institution or a law enforcement official having lawful custody of an individual, if the correctional institution or law enforcement official represents that such information is necessary for the provision of health care to such individual, the health and safety of other individuals or others at the correctional institution, or the administration and maintenance of the safety, security, and good order of the correctional institution;

—To appropriate domestic or foreign government officials (including but not limited to the U.S. Department of Labor), as authorized by and to the extent necessary to comply with laws relating to workers' compensation or other similar programs, established by law, that provide benefits for work-related injuries or illnesses without regard to fault.

Policies and practices for storing, retrieving, accessing, retaining, and disposing of records in the system:

Storage:

Records are stored in hard copy and computer media.

Retrievability:

By individual name and date of birth.

Safeguards:

All users are given information system security awareness training, including the procedures for handling Sensitive but Unclassified and personally identifiable information. Annual refresher training is mandatory. Before being granted access to Medical Records, a user must first be granted access to the Department of State computer system.

Remote access to the Department of State network from non-Department owned systems is only authorized through a Department approved access program. Remote access to the network is configured with the Office of Management and Budget Memorandum M–07–16 security requirements of two factor authentication and time out function.

All Department of State employees and contractors with authorized access have undergone a thorough background security investigation. Access to the Department of State, its annexes and posts overseas is controlled by security guards and admission is limited to those individuals possessing a valid identification card or individuals under proper escort. All records containing Medical Records information are maintained in secured file cabinets in restricted areas, access to which is limited to authorized personnel. Access to computerized files is password-protected and under the direct supervision of the system manager. The system manager has the capability of printing audit trails of access from the computer media, thereby permitting regular and ad hoc monitoring of computer usage.

When it is determined that a user no longer needs access, the user accounted is disabled.

Retention and disposal:

Records are retired or destroyed in accordance with published schedules of the Department of State. More specific information may be obtained by writing the Director of Medical Records, Office of Medical Services, 2401 E Street, NW., Washington, DC 20522.

System manager(s) and address:

Executive Officer, Medical Services, Room 2270, Department of State, 2401 E Street, NW., Washington, DC 20522.

Notification procedure:

Individuals who have cause to believe that the Office of Medical Services might have records pertaining to them should write to Medical Records, Office of Medical Services, Department of State, 2401 E Street NW., Washington, DC 20522. The individual must include: Name; date and place of birth; current mailing address and zip code; signature; the agency served by the medical program with which the individual was or is an employee or a dependent, and the approximate dates of such employment or dependency.

Record access procedures:

Individuals who wish to gain access to or amend records pertaining to them should write to the Director of Medical Records (Address above).

Contesting record procedures:

(See Record access procedure, above).

Record source categories:

Information contained in these records comes from the individual; hospitals; clinics; private physicians; employers; and medical professionals employed by the Department of State.

System exempted from certain provisions under the Privacy Act:

None.

[FR Doc. E9–12146 Filed 5–22–09; 8:45 am]

BILLING CODE 4710–24–P

SUSQUEHANNA RIVER BASIN COMMISSION

Notice of Projects Approved for Consumptive Uses of Water

AGENCY: Susquehanna River Basin Commission.

ACTION: Notice of approved projects.

SUMMARY: This notice lists the projects approved by rule by the Susquehanna River Basin Commission during the period set forth in **DATES**.

DATES: January 1, 2009, through April 30, 2009.

ADDRESSES: Susquehanna River Basin Commission, 1721 North Front Street, Harrisburg, PA 17102–2391.

FOR FURTHER INFORMATION CONTACT: Richard A. Cairo, General Counsel, telephone: (717) 238–0423, ext. 306; fax: (717) 238–2436; e-mail: *rcairo@srbc.net* or Stephanie L. Richardson, Secretary to the Commission, telephone: (717) 238–0423, ext. 304; fax: (717) 238–2436; e-mail: *srichardson@srbc.net.* Regular mail inquiries may be sent to the above address.

SUPPLEMENTARY INFORMATION: This notice lists the projects, described below, receiving approval for the consumptive use of water pursuant to the Commission's approval by rule process set forth in 18 CFR 806.22(e) and 18 CFR 806.22(f) for the time period specified above:

Approvals Issued

Approvals By Rule Issued Under 18 CFR 806.22(e)

1. Church & Dwight Co., Inc., Arm and Hammer, ABR20081205, Jackson Township, York County, PA, Consumptive Use of Up to 0.420 mgd, Approval Date: January 14, 2009.
2. ADM Cocoa, ADM Cocoa—Hazleton, PA, ABR20090302, Hazle Township, Luzerne County, PA, Consumptive Use of Up to 0.160 mgd, Approval Date: March 24, 2009.

Approvals By Rule Issued Under 18 CFR 806.22(f)

1. Alta Operating Company, LLC, Webster #1, ABR20090401, Franklin Township, Susquehanna County, PA, Consumptive Use of Up to 0.990 mgd, Approval Date: April 6, 2009.
2. Alta Operating Company, LLC, Holbrook #1, ABR20090402, Bridgewater Township, Susquehanna County, PA, Consumptive Use of Up to 0.999 mgd, Approval Date: April 6, 2009.
3. Alta Operating Company, LLC, Turner #1, ABR20090403, Liberty Township, Susquehanna County, PA,

Consumptive Use of Up to 0.999 mgd, Approval Date: April 6, 2009.

4. Alta Operating Company, LLC, Fiondi #1, ABR20090404, Middletown Township, Susquehanna County, PA, Consumptive Use of Up to 0.999 mgd, Approval Date: April 6, 2009.

5. Anadarko E&P Company, LP, COP Tract 653 (1000), ABR20090405, Beech Creek Township, Clinton County, PA, Consumptive Use of Up to 1.680 mgd, Approval Date: April 6, 2009.

6. Anadarko E&P Company, LP, COP Tract 231 (1000), ABR20090406, Boggs Township, Centre County, PA, Consumptive Use of Up to 1.680 mgd, Approval Date: April 6, 2009.

7. Anadarko E&P Company, LP, Larry's Creek F&G #1, ABR20090407, Cummings Township, Lycoming County, PA, Consumptive Use of Up to 1.680 mgd, Approval Date: April 6, 2009.

8. Anadarko E&P Company, LP, COP Tract 285 (1000), ABR20090408, Grugan Township, Clinton County, PA, Consumptive Use of Up to 1.680 mgd, Approval Date: April 6, 2009.

9. Anadarko E&P Company, LP, Penn State Forest Tract 289 #1, ABR20090409, McHenry Township, Lycoming County, PA, Consumptive Use of Up to 1.680 mgd, Approval Date: April 6, 2009.

10. Anadarko E&P Company, LP, COP Tract 289 #1000H and #1001H, ABR20090410, McHenry Township, Lycoming County, PA, Consumptive Use of Up to 5.000 mgd, Approval Date: April 6, 2009.

11. Anadarko E&P Company, LP, Larry's Creek F&G #2H, ABR20090411, Cummings Township, Lycoming County, PA, Consumptive Use of Up to 5.000 mgd, Approval Date: April 6, 2009.

12. Anadarko E&P Company, LP, COP Tract 231 #1001H and #1002H, ABR20090412, Snow Shoe Township, Centre County, PA, Consumptive Use of Up to 5.000 mgd, Approval Date: April 6, 2009.

13. Anadarko E&P Company, LP, COP Tract 285 #1001H and #1002H, ABR20090413, Grugan Township, Clinton County, PA, Consumptive Use of Up to 5.000 mgd, Approval Date: April 6, 2009.

14. Anadarko E&P Company, LP, COP Tract 653 #1001H, ABR20090414, Beech Creek Township, Clinton County, PA, Consumptive Use of Up to 5.000 mgd, Approval Date: April 6, 2009.

15. Anadarko E&P Company, LP, COP Tract 653 #1002H, ABR20090415, Beech Creek Township, Clinton County, PA, Consumptive Use of Up to 5.000 mgd, Approval Date: April 6, 2009.

16. Anadarko E&P Company, LP, Larry's Creek F&G #3H, ABR20090416, Cummings Township, Lycoming County, PA, Consumptive Use of Up to 5.000 mgd, Approval Date: April 6, 2009.

17. Carrizo Oil & Gas, Inc., Cowfer #1, ABR20090417, Rush Township, Centre County, PA, Consumptive Use of Up to 0.999 mgd, Approval Date: April 6, 2009.

18. Eastern American Energy Corporation, Whitetail Gun & Rod Club #1, ABR20090418, Goshen Township, Clearfield County, PA, Consumptive Use of Up to 0.900 mgd, Approval Date: April 6, 2009.

19. EOG Resources, Inc., Houseknecht #2H, ABR20090419, Springfield Township, Bradford County, PA, Consumptive Use of Up to 0.490 mgd, Approval Date: April 6, 2009.

20. EOG Resources, Inc., Houseknecht C 1V, ABR20090420, Springfield Township, Bradford County, PA, Consumptive Use of Up to 0.099 mgd, Approval Date: April 6, 2009.

21. EOG Resources, Inc., Ward M 1H, ABR20090421, Springfield Township, Bradford County, PA, Consumptive Use of Up to 0.490 mgd, Approval Date: April 6, 2009.

22. EOG Resources, Inc., Houseknecht 3H, ABR20090422, Springfield Township, Bradford County, PA, Consumptive Use of Up to 0.490 mgd, Approval Date: April 6, 2009.

23. EOG Resources, Inc., Houseknecht 1H, ABR20090423, Springfield Township, Bradford County, PA, Consumptive Use of Up to 0.499 mgd, Approval Date: April 6, 2009.

24. EOG Resources, Inc., PHC 3H, ABR20090424, Lawrence Township, Clearfield County, PA, Consumptive Use of Up to 0.499 mgd, Approval Date: April 6, 2009.

25. EXCO–North Coast Energy, Inc., Litke (1H and 2H), ABR20090425, Burnside Township, Centre County, PA, Consumptive Use of Up to 2.000 mgd, Approval Date: April 6, 2009.

26. EXCO–North Coast Energy, Inc., Litke (7H and 8H), ABR20090426, Burnside Township, Centre County, PA, Consumptive Use of Up to 2.000 mgd, Approval Date: April 6, 2009.

27. EXCO–North Coast Energy, Inc., Sterling Run Club #4, ABR20090427, Burnside Township, Centre County, PA, Consumptive Use of Up to 1.000 mgd, Approval Date: April 6, 2009.

28. EXCO–North Coast Energy, Inc., Sterling Run Club #5, ABR20090428, Burnside Township, Centre County, PA, Consumptive Use of Up to 1.000 mgd, Approval Date: April 6, 2009.

29. EXCO–North Coast Energy, Inc., Derrick Unit #1, ABR20090429, Franklin Township, Lycoming County, PA, Consumptive Use of Up to 1.600 mgd, Approval Date: April 6, 2009.

30. EXCO–North Coast Energy, Inc., Snyder Unit #1, ABR20090430, Franklin Township, Lycoming County, PA, Consumptive Use of Up to 1.600 mgd, Approval Date: April 6, 2009.

31. EXCO–North Coast Energy, Inc., Litke (14H, 15H, 16H), ABR20090431, Burnside Township, Centre County, PA, Consumptive Use of Up to 5.000 mgd, Approval Date: April 6, 2009.

32. Seneca Resources Corporation, DCNR 595 1V, ABR20090432, Bloss Township, Tioga County, PA, Consumptive Use of Up to 0.099 mgd, Approval Date: April 6, 2009.

33. Seneca Resources Corporation, Wilcox (TEOG 1), ABR20090433, Covington Township, Tioga County, PA, Consumptive Use of Up to 0.099 mgd, Approval Date: April 6, 2009.

34. Seneca Resources Corporation, Hemenway (TSRC 1), ABR20090434, Charleston County, Tioga County, PA, Consumptive Use of Up to 0.099 mgd, Approval Date: April 6, 2009.

35. Seneca Resources Corporation, DCNR 293, ABR20090435, Cummings Township, Lycoming County, PA, Consumptive Use of Up to 0.099 mgd, Approval Date: April 6, 2009.

36. Seneca Resources Corporation, DCNR 100 1V, ABR20090436, Lewis Township, Lycoming County, PA, Consumptive Use of Up to 0.099 mgd, Approval Date: April 6, 2009.

37. Southwestern Energy Production Co., Greenzweig [1 (706575)], ABR20090437, Herrick Township, Bradford County, PA, Consumptive Use of Up to 1.750 mgd, Approval Date: April 6, 2009.

38. Southwestern Energy Production Co., Range No. (1 and 1H), ABR20090438, New Milford Township, Susquehanna County, PA, Consumptive Use of Up to 1.750 mgd, Approval Date: April 6, 2009.

39. Southwestern Energy Production Co., Price No. 1 Vertical and Horizontal, ABR20090439, Lenox Township, Susquehanna River, PA, Consumptive Use of Up to 1.750 mgd, Approval Date: April 6, 2009.

40. Anadarko E&P Company, LP, COP Tract 259 #1001H, ABR20090440, Burnside Township, Centre County, PA, Consumptive Use of Up to 5.000 mgd, Approval Date: April 27, 2009.

41. Anadarko E&P Company, LP, COP Tract 259 #1002H, ABR20090441, Burnside Township, Centre County, PA, Consumptive Use of Up to 5.000 mgd, Approval Date: April 27, 2009.

42. Anadarko E&P Company, LP, R. Carlin #1H, ABR20090442, Snow Shoe Township, Centre County, PA,

Consumptive Use of Up to 5.000 mgd, Approval Date: April 27, 2009.

43. Anadarko E&P Company, LP, R. Carlin #2H and #3H, ABR20090443, Snow Shoe Township, Centre County, PA, Consumptive Use of Up to 5.000 mgd, Approval Date: April 27, 2009.

44. Anadarko E&P Company, LP, COP Tract 252 #1000H, ABR20090444, Grugan Township, Clinton County, PA, Consumptive Use of Up to 5.000 mgd, Approval Date: April 27, 2009.

45. Anadarko E&P Company, LP, COP Tract 252 #1001H and #1002H, ABR20090445, Grugan Township, Clinton County, PA, Consumptive Use of Up to 5.000 mgd, Approval Date: April 27, 2009.

Authority: Public Law 91–575, 84 Stat. 1509 *et seq.,* 18 CFR Parts 806, 807, and 808.

Dated: May 6, 2009.

Thomas W. Beauduy,

Deputy Director.

[FR Doc. E9–12047 Filed 5–22–09; 8:45 am]

BILLING CODE 7040–01–P

DEPARTMENT OF TRANSPORTATION

National Highway Traffic Safety Administration

[Docket No. NHTSA–2009–0094]

Notice of Receipt of Petition for Decision That Nonconforming 2006 Ferrari 599 Passenger Cars Manufactured Before September 1, 2006 Are Eligible for Importation

AGENCY: National Highway Traffic Safety Administration, DOT.

ACTION: Notice of receipt of petition for decision that nonconforming 2006 Ferrari 599 passenger cars manufactured before September 1, 2006 are eligible for importation.

SUMMARY: This document announces receipt by the National Highway Traffic Safety Administration (NHTSA) of a petition for a decision that 2006 Ferrari 599 passenger cars manufactured before September 1, 2006 that were not originally manufactured to comply with all applicable Federal motor vehicle safety standards (FMVSS) are eligible for importation into the United States because (1) they are substantially similar to vehicles that were originally manufactured for sale in the United States and that were certified by their manufacturer as complying with the safety standards (the U.S.-certified version of the 2006 Ferrari 599 passenger cars manufactured before September 1, 2006,) and (2) they are capable of being readily altered to conform to the standards.

DATES: The closing date for comments on the petition is June 25, 2009.

ADDRESSES: Comments should refer to the docket and notice numbers above and be submitted 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: Comments must be written in the English language, and be no greater than 15 pages in length, although there is no limit to the length of necessary attachments to the comments. If comments are submitted in hard copy form, please ensure that two copies are provided. If you wish to receive confirmation that your comments were received, please enclose a stamped, self-addressed postcard with the comments. Note that all comments received will be posted without change to *http://www.regulations.gov*, including any personal information provided. Please see the Privacy Act heading below.

Privacy Act: Anyone is able to search the electronic form of all comments received into any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, etc.). You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (65 FR 19477–78) or you may visit *http://DocketInfo.dot.gov.*

How to Read Comments Submitted to the Docket: You may read the comments received by Docket Management at the address and times given above. You may also see the comments on the Internet. To read the comments on the Internet, take the following steps:

(1) Go to the Federal Docket Management System (FDMS) Web page *http://www.regulations.gov.*

(2) On that page, click on ''Advanced Docket Search.''

(3) On the next page select ''NATIONAL HIGHWAY TRAFFIC SAFETY ADMINISTRATION'' from the drop-down menu in the Agency field and enter the Docket ID number shown at the heading of this document.

(4) After entering that information, click on ''submit.''

(5) The next page contains docket summary information for the docket you selected. Click on the comments you wish to see. You may download the comments. Please note that even after the comment closing date, we will continue to file relevant information in the Docket as it becomes available. Further, some people may submit late comments. Accordingly, we recommend that you periodically search the Docket for new material.

FOR FURTHER INFORMATION CONTACT: Coleman Sachs, Office of Vehicle Safety Compliance, NHTSA (202–366–3151).

SUPPLEMENTARY INFORMATION:

Background

Under 49 U.S.C. 30141(a)(1)(A), a motor vehicle that was not originally manufactured to conform to all applicable FMVSS shall be refused admission into the United States unless NHTSA has decided that the motor vehicle is substantially similar to a motor vehicle originally manufactured for importation into and sale in the United States, certified under 49 U.S.C. 30115, and of the same model year as the model of the motor vehicle to be compared, and is capable of being readily altered to conform to all applicable FMVSS.

Petitions for eligibility decisions may be submitted by either manufacturers or importers who have registered with NHTSA pursuant to 49 CFR Part 592. As specified in 49 CFR 593.7, NHTSA publishes notice in the **Federal Register** of each petition that it receives, and affords interested persons an opportunity to comment on the petition. At the close of the comment period, NHTSA decides, on the basis of the petition and any comments that it has received, whether the vehicle is eligible for importation. The agency then publishes this decision in the **Federal Register**.

Wallace Environmental Testing Laboratories, Inc. (WETL) of Houston, TX (Registered Importer 90–005) has petitioned NHTSA to decide whether nonconforming 2006 Ferrari 599 passenger cars manufactured before September 1, 2006 are eligible for importation into the United States. The vehicles which WETL believes are substantially similar are 2006 Ferrari 599 passenger cars manufactured before September 1, 2006 that were manufactured for sale in the United States and certified by their manufacturer as conforming to all applicable FMVSS.

The petitioner claims that it compared non-U.S. certified 2006 Ferrari 599 passenger cars manufactured before September 1, 2006 to their U.S.-certified counterparts, and found the vehicles to be substantially similar with respect to compliance with most FMVSS.

WETL submitted information with its petition intended to demonstrate that non-U.S. certified 2006 Ferrari 599 passenger cars manufactured before September 1, 2006, as originally manufactured, conform to many FMVSS in the same manner as their U.S. certified counterparts, or are capable of being readily altered to conform to those standards.

Specifically, the petitioner claims that non-U.S. certified 2006 Ferrari 599 passenger cars manufactured before September 1, 2006 are identical to their U.S. certified counterparts with respect to compliance with Standard Nos. 102 *Transmission Shift Lever Sequence, Starter Interlock, and Transmission Braking Effect,* 103 *Windshield Defrosting and Defogging Systems,* 104 *Windshield Wiping and Washing Systems,* 106 *Brake Hoses,* 109 *New Pneumatic Tires,* 113 *Hood Latch System,* 116 *Motor Vehicle Brake Fluids,* 118 *Power-Operated Window, Partition, and Roof Panel Systems,* 124 *Accelerator Control Systems,* 135 *Passenger Car Brake Systems,* 201 *Occupant Protection in Interior Impact,* 202 *Head Restraints,* 204 *Steering Control Rearward Displacement,* 205 *Glazing Materials,* 206 *Door Locks and Door Retention Components,* 207 *Seating Systems,* 212 *Windshield Mounting,* 214 *Side Impact Protection,* 216 *Roof Crush Resistance,* 219 *Windshield Zone Intrusion,* 302 *Flammability of Interior Materials,* and 401 *Interior Trunk Release.*

In addition, the petitioner claims that the vehicles comply with the Bumper Standard found in 49 CFR Part 581.

The petitioner also contends that the vehicles are capable of being readily altered to meet the following standards, in the manner indicated:

Standard No. 101 *Controls and Displays:* Inspection of all vehicles and installation of a U.S.-model instrument cluster with associated hardware and software, or modification of the existing instrument cluster to meet the requirements of this standard on vehicles not already so equipped.

Standard No. 108 *Lamps, Reflective Devices and Associated Equipment:* Inspection of all vehicles and installation, on vehicles that are not already so equipped, of U.S.-model components to meet the requirements of this standard.

Standard No. 110 *Tire Selection and Rims:* Installation of a tire information placard on all vehicles not already so equipped.

Standard No. 111 *Rearview Mirrors:* Inspection of all vehicles and installation of a U.S.-model passenger side rearview mirror, or inscription of the required warning statement on the face of that mirror on all vehicles not already so equipped.

Standard No. 114 *Theft Protection:* Inspection of all vehicles and installation of a supplemental key warning buzzer, or installation of U.S.-version software on all vehicles not already so equipped.

Standard No. 208 *Occupant Crash Protection:* Inspection of all vehicles and replacement of any non U.S.-model seat belts, air bag control units, air bags, and sensors with U.S.-model components on vehicles that are not already so equipped; and (b) installation of U.S.-version software to ensure that the seat belt warning system meets the requirements of this standard.

The petitioner states that the crash protection system used in these vehicles consists of dual front airbags, knee bolsters, and combination lap and shoulder belts at the front outboard seating positions. The seat belt systems are described as being self-tensioning, and capable of being released by means of a single red push-button.

Standard No. 209 *Seat Belt Assemblies:* Inspection of all vehicles and replacement of any non U.S.-model seat belts with U.S.-certified model seat belts.

Standard No. 210 *Seat Belt Assembly Anchorages:* Inspection of all vehicles and replacement of any non U.S.-model seat belts anchorage components with U.S.-model components.

Standard No. 225 *Child Restraint Anchorage Systems:* Installation of U.S.-model child restraint systems.

Standard No. 301 *Fuel System Integrity:* Inspection of all vehicles and replacement of any non U.S.-model fuel system components with U.S.-model components.

The petitioner additionally states that a vehicle identification plate must be affixed to the vehicles near the left windshield post to meet the requirements of 49 CFR Part 565.

All comments received before the close of business on the closing date indicated above will be considered, and will be available for examination in the docket at the above addresses both before and after that date. To the extent possible, comments filed after the closing date will also be considered. Notice of final action on the petition will be published in the **Federal Register** pursuant to the authority indicated below.

Authority: 49 U.S.C. 30141(a)(1)(A) and (b)(1); 49 CFR 593.8; delegations of authority at 49 CFR 1.50 and 501.8.

Issued on: May 19, 2009.

Harry Thompson,

Acting Director, Office of Vehicle Safety Compliance.

[FR Doc. E9–12154 Filed 5–22–09; 8:45 am]

BILLING CODE 4910–59–P

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[STB Finance Docket No. 35164; STB Docket No. AB–6 (Sub-No. 430X)]

BNSF Railway Company-Petition for Declaratory Order; BNSF Railway Company—Abandonment Exemption—in Oklahoma County, OK

AGENCY: Surface Transportation Board, DOT.

ACTION: Notice of board action.

SUMMARY: The Surface Transportation Board (Board) hereby gives notice that, on its own motion, it granted BNSF Railway Company (BNSF) exemptions under 49 U.S.C. 10502 from the provisions of 49 U.S.C. 10903 (filing and procedure for application to abandon or discontinue service), 49 U.S.C. 10904 (offers of financial assistance to avoid abandonment and discontinuance), and 49 U.S.C. 10905 (offering abandoned rail properties for sale for public purposes) for a segment of track on the Chickasha Line in Oklahoma City, OK, between milepost 541.69 and milepost 540.15 (the middle segment). The Board took this action in a decision served earlier in which it also found that a BNSF eastern segment project was a relocation that did not require prior agency authorization.

FOR FURTHER INFORMATION CONTACT: Joseph Dettmar, (202) 245–0395. [Assistance for the hearing impaired is available through the Federal Information Relay Service (FIRS) at: (800) 877–8339.]

SUPPLEMENTARY INFORMATION: By petition filed on July 15, 2008, BNSF asked the Board to issue a declaratory order finding that what it characterized as two track relocation projects in Oklahoma City, OK did not require Board approval.

The Board granted the requested declaratory relief as to the eastern segment. On the middle segment, Board concluded that the evidence before it in the two related dockets had provided ample support for authorizing abandonment of that segment. The evidence indicates that: the three existing shippers on adjoining segments will continue to receive local service; all overhead service can be rerouted; no one has requested local service on the middle segment in over 10 years; and there is no indication of any need for service on the middle segment in the future. Finally, because any traffic that might need to move over the middle segment could move over a refurbished BNSF Line (the Packingtown Lead), the public convenience and necessity does not require BNSF to keep the middle segment in the national rail system. Accordingly, the Board on its own motion granted BNSF an exemption from the provisions of 49 U.S.C. 10903 for the middle segment.

In seeking a declaratory order, BNSF also asked the Board for an expedited decision so that the relocation project to facilitate the construction of the I–40 highway could go forward. The Board, on its own motion, exempted the abandonment of the middle segment from the statutory offer of financial assistance (OFA) program so that the highway project may proceed and because applying the OFA provisions under 49 U.S.C. 10904 is not necessary to carry out the rail transportation policy.

Lastly, the Board granted an exemption on its own motion from the public use provisions under 49 U.S.C. 10905. BNSF has already agreed to make the right-of-way available to Oklahoma Department of Transportation (ODOT) for public use, *i.e.*, the construction of I–40. Therefore, the purpose sought to be achieved by section 10905—to provide an opportunity to public bodies to negotiate for the acquisition of abandoned rail properties—has already been fulfilled by the agreement reached between BNSF and ODOT.

This action will not significantly affect either the quality of the human environment or the conservation of energy resources.

Decided: May 19, 2009.

By the Board, Acting Chairman Mulvey, and Vice Chairman Nottingham.

Andrea Pope-Matheson,

Clearance Clerk.

[FR Doc. E9–12099 Filed 5–22–09; 8:45 am]

BILLING CODE 4915–01–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

[Summary Notice No. PE–2009–15]

Petition for Exemption; Summary of Petition Received

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of petition for exemption received.

SUMMARY: This notice contains a summary of a petition seeking relief from specified requirements of 14 CFR. The purpose of this notice is to improve the public's awareness of, and participation in, this aspect of FAA's regulatory activities. Neither publication of this notice nor the inclusion or omission of information in the summary is intended to affect the legal status of the petition or its final disposition.

DATES: Comments on this petition must identify the petition docket number involved and must be received on or before June 15, 2009.

ADDRESSES: You may send comments identified by Docket Number FAA–2009–0250 using any of the following methods:

- *Government-wide rulemaking Web site:* Go to *http://www.regulations.gov* and follow the instructions for sending your comments electronically.
- *Mail:* Send comments to the Docket Management Facility; U.S. Department of Transportation (DOT), 1200 New Jersey Avenue, SE., West Building Ground Floor, Room W12–140, Washington, DC 20590.
- *Fax:* Fax comments to the Docket Management Facility at 202–493–2251.
- *Hand Delivery:* Bring comments to the Docket Management Facility in Room W12–140 of the West Building Ground Floor at 1200 New Jersey Avenue, SE., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Privacy: We will post all comments we receive, without change, to *http://www.regulations.gov*, including any personal information you provide. Using the search function of our docket Web site, anyone can find and read the comments received into any of our dockets, including the name of the individual sending the comment (or signing the comment for 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).

Docket: To read background documents or comments received, go to *http://www.regulations.gov* at any time or to the Docket Management Facility in Room W12–140 of the West Building Ground Floor at 1200 New Jersey Avenue, SE., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: Laverne Brunache (202) 267–3133 or Tyneka Thomas (202) 267–7626, Office of Rulemaking, Federal Aviation Administration, 800 Independence Avenue, SW., Washington, DC 20591.

This notice is published pursuant to 14 CFR 11.85.

Issued in Washington, DC, on May 20, 2009.

Pamela Hamilton-Powell,

Director, Office of Rulemaking.

Petition for Exemption

Docket No.: FAA–2009–0250.

Petitioner: Ameristar Air Cargo, Inc.

Section of 14 CFR Affected: 14 CFR 121.434(h)(3).

Description of Relief Sought: Ameristar Air Cargo, Inc. (Ameristar), has petitioned the Federal Aviation Administration to permit a pilot that meets certain conditions outlined in its petition, but not the requirements of 14 CFR 121.434(g), to serve as a pilot in an airplane for which the pilot has newly qualified. Additionally, Ameristar wishes to operate under such an exemption outside the United States, specifically: Canada, Mexico, Central America, South America, and the Caribbean nations or areas of operations authorized in its operations specifications.

[FR Doc. E9–12091 Filed 5–22–09; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Motor Carrier Safety Administration

Purpose, Use and Effect of Field Operations Training Manual.

AGENCY: Federal Motor Carrier Safety Administration (FMCSA), DOT.

ACTION: Notice of Interpretation of Internal Agency Document.

SUMMARY: The purpose of this notice is to restate and confirm the Agency's policy regarding the purpose, use and effect of the paper and electronic versions of FMCSA's Field Operations Training Manual (FOTM and eFOTM).

DATES: *Effective Date:* This interpretation restates policy already in effect.

FOR FURTHER INFORMATION CONTACT: Peter Snyder, Trial Attorney, Office of the Chief Counsel, Enforcement Division, 19900 Governors Drive, Suite 210, Olympia Fields, IL 60461, telephone (708) 283–3515; or Genevieve Sapir, Attorney-Advisor, Office of the Chief Counsel, Regulatory Affairs Division, 1200 New Jersey Avenue, SE., Washington, DC 20590, telephone (202) 366–7056.

Background

The Motor Carrier Safety Improvement Act of 1999 (MCSIA) established the Federal Motor Carrier Safety Administration (''FMCSA'') as a new operating administration within the Department of Transportation, effective January 1, 2000 (Pub. L. 106–159, 113 Stat. 1748, December 9, 1999). Continuing the practice first established by FMCSA's predecessors, the Office of Motor Carriers and the Office of Motor Carrier Safety, both within the Federal Highway Administration, FMCSA issues guidance to its Field Service Centers and State Division Offices, in the form of the Field Operations Training Manual (FOTM). Volume III (Enforcement: General Functions of an Investigator) of the first FOTM, which was issued by the new operating administration in January 2000, states: ''This chapter has been prepared to assist the Investigator in the performance of investigative work. The intent is to present investigative procedures which can be used while conducting all types of investigations.'' This guidance is now stored and distributed in electronic format in the eFOTM, which is periodically updated as new policies are adopted in response to legislation and new program initiatives. A redacted version of the eFOTM is available in the FMCSA Electronic Reading Room at: *http://www.fmcsa.dot.gov/foia/electronicreadingroom.htm.* FMCSA redacted certain information from the eFOTM available at this Web site in accordance with the Freedom of Information Act.

The eFOTM is, and has been, best characterized as internal enforcement guidelines, a ''best practices'' guide for the Agency's Safety Investigators and other enforcement staff. It is intended to provide guidance to assist with the sound exercise of discretion in conducting investigations, compliance reviews, roadside inspections and safety audits. The United States Court of Appeals for the District of Columbia Circuit recognized that the FOTM does not impose new substantive burdens, in the sense that it neither requires nor prohibits any particular actions on the part of motor carriers. *Aulenback, Inc.* v. *Federal Highway Admin.,* 103 F.3d 156, 169 (DC Cir. 1997). Instead, ''the Manual simply provides guidance for [FMCSA staff] seeking to identify motor carrier operations that pose a potential danger to public safety.'' *Id.* The District of Columbia Circuit has also held that since the FOTM is not a legislative rule, section 553 of the Administrative Procedure Act did not require notice and comment rulemaking to precede adoption of the manual. *American Trucking Ass'ns, Inc.* v. *DOT,* 166 F.3d 374 (DC Cir. 1999).

Current Policy

The Agency continues to regard the FOTM and eFOTM as internal enforcement guidance; the guidance does not alter underlying substantive legal requirements and does not provide an independent basis for enforcement. The investigatory procedures set forth in the eFOTM, and whether and to what extent Agency employees follow them, are not relevant in determining whether Federal motor carrier statutes or regulations have been violated or the appropriate penalty to be assessed for such violations. If an employee fails to comply with investigative, inspection, audit or other guidelines, the Agency will address that departure from recommended procedures internally, on a case-by-case basis, and may consider disciplinary action, training or other appropriate measures. However, the Agency hereby provides public notice that it will not consider an FMCSA or State employee's failure to follow the FOTM or eFOTM guidance as a defense to penalties or violations assessed against drivers or motor carriers. An FMCSA or State employee's failure to follow the FOTM or eFOTM guidance will not excuse violations of the Federal Motor Carrier Safety Regulations, Federal Motor Carrier Commercial Regulations, or the Hazardous Materials Regulations by any person, including motor carriers and drivers, nor will it provide grounds for reducing civil penalties. *See In the Matter of J. Line, Inc., dba J-Line Transp.,* Docket No. FMCSA–2008–1087 (Administrative Law Judge's Order Denying Cross-Motions for Final Order) (Jan. 13, 2009); *Swift Transp. Co., Inc.,* Docket No. FMCSA–2004–17248–63 (Order Respecting Field Operations Training Manual) (Jan. 12, 2007).

Issued on: May 19, 2009.

Rose A. McMurray,

Acting Deputy Administrator.

[FR Doc. E9–12136 Filed 5–22–09; 8:45 am]

BILLING CODE 4910–EX–P

DEPARTMENT OF THE TREASURY

Submission for OMB Review; Comment Request

May 18, 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 date of publication 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 June 25, 2009 to be assured of consideration.

Financial Crimes Enforcement Network (FinCEN)

OMB Number: 1506–0005.
Type of Review: Revision.
Form: FinCEN 103.
Title: Currency Transaction Report by Casinos.
Description: Casinos and card clubs file Form 103 for currency transactions in excess of $10,000 a day pursuant to 31 U.S.C. 5313(a) and 31 CFR 103.22(a)(2). The form is used by criminal investigators, and taxation and regulatory enforcement authorities, during the course of investigations involving financial crimes.
Respondents: Businesses or other for-profits.
Estimated Total Reporting Burden: 230,000 hours.

OMB Number: 1506–0014.
Type of Review: Extension .
Form: FINCEN–105.
Title: Report of International Transportation of Currency or Monetary Instruments.
Description: FinCEN, and the Department of Homeland Security (DHS) and the DHS Bureaus, are required under 31 U.S.C. 5316(a) to collect information regarding mailing, shipment, or transportation of currency or monetary instruments of more than $10,000 in value into or out of the United States
Respondents: Individuals or Households
Estimated Total Reporting Burden: 140,000 hours.

OMB Number: 1506–0033.
Type of Review: Extension.
Title: Customer Identification Programs for Mutual Funds.
Description: Mutual Funds are required to establish and maintain customer identification programs. A copy of the written program must be maintained for five years. *See* 31 CFR 103.131.
Respondents: Businesses or other for-profits.
Estimated Total Reporting Burden: 266,700 hours.

OMB Number: 1506–0026.
Type of Review: Extension.
Title: Customer identification programs for banks, savings associations, credit unions, and certain non-federally regulated banks.
Description: Banks, savings associations, credit unions, and certain non-federally regulated banks are required to develop and maintain customer identification programs. *See* 31 CFR 103.121.
Respondents: Businesses or other for-profits.
Estimated Total Reporting Burden: 242,660 hours.

OMB Number: 1506–0006.
Type of Review: Revision.
Form: 102.
Title: Suspicious Activity Report by Casinos and Card Clubs.
Description: Under 31 CFR 103.21, the Treasury is requiring casinos and card clubs with annual gaming revenue of more than $1,000,000 to report suspicious activities.
Respondents: Businesses or other for-profits.
Estimated Total Reporting Burden: 33,600 hours.
Clearance Officer: Russell Stephenson (202) 354–6012, Department of the Treasury, Financial Crimes Enforcement Network, P.O. Box 39, Vienna, VA 22183.
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. E9–12125 Filed 5–22–09; 8:45 am]
BILLING CODE 4810–02–P

DEPARTMENT OF THE TREASURY

Submission for OMB Review; Comment Request

May 18, 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 date of publication 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, and 1750 Pennsylvania Avenue, NW., Washington, DC 20220.

DATES: Written comments should be received on or before June 25, 2009 to be assured of consideration.

Internal Revenue Service (IRS)

OMB Number: 1545–1806.
Type of Review: Revision.
Form: 8883.
Title: Asset Allocation Statement Under 338.
Description: Form 8883 is used to report information regarding transactions involving the deemed sale of corporate assets under section 338.
Respondents: Businesses or other for-profits.
Estimated Total Burden Hours: 4,881 hours.

OMB Number: 1545–1536.
Type of Review: Extension.
Title: Guidance Regarding Charitable Remainder Trusts and Special Valuation Rules for Transfer of Interests in Trusts REG–209823–96 (Final).
Description: The recordkeeping requirement in the regulation provides taxpayers with an alternative method for complying with Congressional intent regarding charitable remainder trusts. The recordkeeping alternative may be less burdensome for taxpayers.
Respondents: Businesses or other for-profits.
Estimated Total Burden Hours: 75 hours.

OMB Number: 1545–0132.
Type of Review: Extension.
Form: 1120–X.
Title: Amended U.S. Corporation Income Tax Return.
Description: Domestic corporations use Form 1120X to correct a previously filed Form 1120 or 1120A. The data is used to determine if the correct tax liability has been reported.
Respondents: Businesses or other for-profits.
Estimated Total Burden Hours: 300,582 hours.

OMB Number: 1545–1965.
Type of Review: Extension.
Title: REG–133446–03 (Final) Guidance on Passive Foreign Company (PFIC) Purging Elections.
Description: The IRS needs the information to substantiate the taxpayer's computation of the taxpayer's share of the PFIC's post-1986 earning and profits.
Respondents: Individuals or Households.
Estimated Total Burden Hours: 250 hours.
Clearance Officer: R. Joseph Durbala (202) 622–3634, Internal Revenue Service, Room 6516, 1111 Constitution Avenue, NW., Washington, DC 20224.
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. E9–12131 Filed 5–22–09; 8:45 am]
BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Submission for OMB Review; Comment Request

May 19, 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 date of publication 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 June 25, 2009 to be assured of consideration.

Financial Crimes Enforcement Network (FinCEN)

OMB Number: 1506–0022.
Type of Review: Revision.
Title: Customer Identification Programs for Futures Commission Merchants and Introducing Brokers.
Description: Futures commission merchants and introducing brokers are required to develop and maintain a customer identification program. A copy of the program must be maintained for five years. *See 31 CFR 103.123.*
Respondents: Businesses or other for-profits.
Estimated Total Reporting Burden: 307,065 hours.

OMB Number: 1506–0034.
Type of Review: Extension.
Title: Customer Identification Programs for Broker-Dealers.
Description: Broker-dealers are required to establish and maintain a customer identification program. A copy of the program must be maintained for five years. *See 31 CFR 103.122.*
Respondents: Businesses or other for-profits.
Estimated Total Reporting Burden: 630,896 hours.
Clearance Officer: Russell Stephenson (202) 354–6012, Department of the Treasury, Financial Crimes Enforcement

Network, P.O. Box 39, Vienna, VA 22183.

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. E9–12126 Filed 5–22–09; 8:45 am]

BILLING CODE 4810–02–P

DEPARTMENT OF THE TREASURY

Submission for OMB Review; Comment Request

May 19, 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 date of publication 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 June 25, 2009 to be assured of consideration.

Internal Revenue Service (IRS)

OMB Number: 1545–1822.

Type of Review: Extension.

Title: Revenue Procedure 2003–11, Offshore Voluntary Compliance Initiative.

Description: Revenue Procedure 2003–11 describes the Offshore Voluntary Compliance Initiative, which is directed at taxpayers that have under-reported their tax liability through financial arrangements outside the United States that rely on the use of credit, debit, or charge cards (offshore credit cards) or foreign banks, financial institutions, corporations, partnership, trusts, or other entities (offshore financial arrangements). Taxpayers that participate in the initiative and provide the information and material that their participation requires can avoid certain penalties.

Respondents: Individuals or Households.

Estimated Total Burden Hours: 100,000 hours.

OMB Number: 1545–1516.

Type of Review: Extension.

Form: 8832.

Title: Entity Classification Election.

Description: An eligible entity that chooses not to be classified under the default rules or that wishes to change its current classification must file Form 8832 to elect a classification.

Respondents: Businesses or other for-profits.

Estimated Total Burden Hours: 23,200 hours.

OMB Number: 1545–1434.

Type of Review: Extension.

Title: CO–26–96 (Final) Regulations Under Section 382 of the Internal Revenue Code of 1986; Application of Section 382 in Short Taxable Years and With Respect to Controlled Groups.

Description: Section 382 limits the amount of income that can be offset by loss carryovers after an ownership change. These regulations provide rules for applying section 382 in the case of short taxable years and with respect to controlled groups.

Respondents: Businesses or other for-profits.

Estimated Total Burden Hours: 875 hours.

OMB Number: 1545–1380.

Type of Review: Extension.

Title: IA–17–90 (Final) Reporting Requirements for Recipients of Points paid on residential mortgages.

Description: To encourage compliance with the tax laws relating to the mortgage interest deduction, the regulations require the reporting on Form 1098 of points paid on residential mortgage. Only businesses that receive mortgage interest in the course of a trade or business are affected by this reporting requirement.

Respondents: Businesses or other for-profits.

Estimated Total Burden Hours: 283,056 hours.

OMB Number: 1545–1241.

Type of Review: Extension.

Title: PS–92–90 (Final) Special Valuation Rules.

Description: Section 2701 of the Internal Revenue Code allows various elections by family members who make gifts of common stock or partnership interests and retain senior interest. The elections affect the value of the gifted interests and the retained interests.

Respondents: Individuals or Households.

Estimated Total Burden Hours: 496 hours.

OMB Number: 1545–1225.

Type of Review: Extension.

Form: 5310–A.

Title: Notice of Plan Merger or Consolidation, Spinoff, or Transfer of Plan Assets or Liabilities; Notice of Qualified Separate Lines of Business.

Description: Plan administrators are required to notify IRS of any plan mergers, consolidations, spinoffs, or transfers of plan assets or liabilities to another plan. Employers are required to notify IRS of separate lines of business for their deferred compensation plans. Form 5310–A is used to make these notifications.

Respondents: Businesses or other for-profits.

Estimated Total Burden Hours: 158,800 hours.

OMB Number: 1545–1540.

Type of Review: Extension.

Title: REG–125071–06 (Final) Reporting Requirements for Widely Held Fixed Investment Trusts (TD 9308) (previously TD 9279).

Description: The regulations clarify the reporting requirements of trustees and middlemen involved with widely held fixed investment trusts.

Respondents: Businesses or other for-profits.

Estimated Total Burden Hours: 2,400 hours.

OMB Number: 1545–1673.

Type of Review: Extension.

Title: Revenue Procedure 2008–50 Employee Plans Compliance Resolution System (previously RP 2006–27).

Description: The information requested in Revenue Procedure 2008–50 is required to enable the Internal Revenue Service to make determinations on the issuance of various types of closing agreements and compliance statements. The issuance of the agreements and statements allows individual plans to maintain their tax-qualified status. As a result, the favorable tax treatment of the benefits of the eligible employees is retained.

Respondents: Businesses or other for-profits.

Estimated Total Burden Hours: 76,222 hours.

OMB Number: 1545–1979.

Type of Review: Extension.

Form: 8908.

Title: Energy Efficient New Home Credit.

Description: Contractors will use Form 8908 to claim the new energy efficient home credit for homes substantially completed after August 8, 2005 and sold for use as personal residences after January 1, 2006.

Respondents: Businesses or other for-profits.

Estimated Total Burden Hours: 512,820 hours.

OMB Number: 1545–1952.

Type of Review: Extension.

Title: Automatic Consent for Eligible Educational Institution to Change Reporting Methods.

Description: This revenue procedure prescribes how an eligible educational institution may obtain automatic consent from the Service to change its method of reporting under section 6050S of the Code and the Income Tax Regulations.

Respondents: Not-for-profit institutions.

Estimated Total Burden Hours: 300 hours.

Clearance Officer: R. Joseph Durbala; (202) 622–3634, Internal Revenue Service, Room 6516, 1111 Constitution Avenue, NW., Washington, DC 20224.

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. E9–12130 Filed 5–22–09; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Low Income Taxpayer Clinic Grant Program; Availability of 2010 Grant Application Package

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice.

SUMMARY: This document contains a Notice that the IRS has made available the grant application package and guidelines (Publication 3319) for organizations interested in applying for a Low Income Taxpayer Clinic (LITC) matching grant for the 2010 grant cycle (the 2010 grant cycle runs January 1, 2010, through December 31, 2010). The application period shall run from May 20, 2009, through July 7, 2009.

The IRS will award a total of up to $6,000,000 (unless otherwise provided by specific Congressional appropriation) to qualifying organizations, subject to the limitations of Internal Revenue Code section 7526, for matching grants. A qualifying organization may receive a matching grant of up to $100,000 per year. Qualifying organizations that provide representation for free or for a nominal fee to low income taxpayers involved in tax controversies with the IRS or that provide education on taxpayer rights and responsibilities to taxpayers for whom English is a second language can apply for a grant for the 2010 grant cycle.

Examples of qualifying organizations include: (1) Clinical programs at accredited law, business or accounting schools, whose students represent low income taxpayers in tax controversies with the IRS, and (2) organizations exempt from tax under I.R.C. § 501(a) which represent low income taxpayers in tax controversies with the IRS or refer those taxpayers to qualified representatives.

DATES: Grant applications for the 2010 grant cycle must be electronically filed, postmarked, sent by private delivery service, or hand-delivered to the LITC Program Office in Washington, DC by July 7, 2009.

ADDRESSES: Send completed grant applications to: Internal Revenue Service, Taxpayer Advocate Service, LITC Grant Program Administration Office, TA:LITC, 1111 Constitution Avenue, NW., Room 1034, Washington, DC 20224. Copies of the *2009 Grant Application Package and Guidelines,* IRS Publication 3319 (Rev. 5–2009), can be downloaded from the IRS Internet site at *http://www.irs.gov/advocate* or ordered from the IRS Distribution Center by calling 1–800–829–3676. Applicants can also file electronically at *http://www.grants.gov.* For applicants applying through the Federal Grants Web site, the Funding Number is TREAS–GRANTS–052010–001.

FOR FURTHER INFORMATION CONTACT: The LITC Program Office at (202) 622–4711 (not a toll-free number) or by e-mail at *LITCProgramOffice@irs.gov.*

SUPPLEMENTARY INFORMATION:

Background

Section 7526 of the Internal Revenue Code authorizes the IRS, subject to the availability of appropriated funds, to award organizations matching grants of up to $100,000 per year for the development, expansion, or continuation of qualified low income taxpayer clinics. Section 7526 authorizes the IRS to provide grants to qualified organizations that represent low income taxpayers in controversies with the IRS or inform individuals for whom English is a second language of their taxpayer rights and responsibilities. The IRS may award grants to qualifying organizations to fund one-year, two-year or three-year project periods. Grant funds may be awarded for start-up expenditures incurred by new clinics during the grant cycle.

The *2010 Grant Application Package and Guidelines,* Publication 3319 (Rev. 5–2009), outlines requirements for the operation of a qualifying LITC program and provides instructions on how to apply for a grant.

The costs of preparing and submitting an application are the responsibility of each applicant. Each application will be given due consideration and the LITC Program Office will notify each applicant, no later than November 27, 2009.

Selection Consideration

Applications that pass the eligibility screening process will be numerically ranked based on the information contained in their proposed program plan. Please note that the IRS Volunteer Income Tax Assistance (VITA) and Tax Counseling for the Elderly (TCE) Programs are independently funded and separate from the LITC Program. Organizations currently participating in the VITA or TCE Programs may be eligible to apply for a LITC grant if they meet the criteria and qualifications outlined in the *2010 Grant Application Package and Guidelines,* Publication 3319 (Rev. 5–2009). Organizations that seek to operate VITA and LITC Programs, or TCE and LITC Programs, must maintain separate and distinct programs even if co-located to ensure proper cost allocation for LITC grant funds and adherence to the rules and regulations of the VITA, TCE and LITC Programs, as appropriate.

Comments

Interested parties are encouraged to provide comments on the IRS's administration of the grant program on an ongoing basis. Comments may be sent to Internal Revenue Service, Taxpayer Advocate Service, Attn: Deborah L. Jones, LITC Program Office, TA:LITC, 1111 Constitution Avenue, NW., Room 1034, Washington, DC 20224.

Nina E. Olson,

National Taxpayer Advocate, Internal Revenue Service.

[FR Doc. E9–12165 Filed 5–22–09; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Office of Thrift Supervision

[Docket ID: OTS–2009–0009]

Open Meeting of the OTS Mutual Savings Association Advisory Committee

AGENCY: Department of the Treasury, Office of Thrift Supervision.

ACTION: Notice of meeting.

SUMMARY: The OTS Mutual Savings Associations Advisory Committee (MSAAC) will convene its first meeting on Tuesday, June 9, 2009, in Conference Room 6A of the Office of Thrift Supervision, 1700 G Street, NW., Washington, DC, beginning at 8:30 a.m. Eastern Time. The meeting will be open to the public.

DATES: The meeting will be held on Tuesday, June 9, 2009, at 8:30 a.m. Eastern Time.

ADDRESSES: The meeting will be held at the Office of Thrift Supervision, 1700 G Street, NW., Washington, DC in Conference Room A. The public is invited to submit written statements to the MSAAC by any one of the following methods:

- *E-mail address: mutualcommittee@ots.treas.gov;* or
- *Mail:* To Charlotte Bahin, Designated Federal Official, Office of Thrift Supervision, 1700 G Street, NW., Washington, DC 20552 in triplicate.

The agency must receive statements no later than June 2, 2009.

FOR FURTHER INFORMATION CONTACT: Charlotte M. Bahin, Designated Federal Official, (202) 906–6452, Office of Thrift Supervision, 1700 G Street, NW., Washington, DC 20552.

SUPPLEMENTARY INFORMATION: By this notice, the Office of Thrift Supervision is announcing that the OTS Mutual Savings Association Advisory Committee will convene its first meeting on Tuesday, June 9, 2009, in Conference Room 6A at the Office of Thrift Supervision, 1700 G Street, NW., Washington, DC, beginning at 8:30 a.m. Eastern Time. The meeting will be open to the public. Because the meeting will be held in a secured facility with limited space, members of the public who plan to attend the meeting, and members of the public who require auxiliary aid, must contact the Office of Thrift Supervision at 202–906–6429 by 5 p.m. Eastern Time on Tuesday, June 2, 2009, to inform OTS of their desire to attend the meeting and to provide the information that will be required to facilitate entry into the OTS building. To enter the building, attendees should provide their full name, e-mail address, date of birth, social security number, organization, and country of citizenship. The purpose of the meeting is to advise OTS on what regulatory changes or other steps OTS may be able to take to ensure the continued health and viability of mutual savings associations, and other issues of concern to the existing mutual savings associations.

Dated: May 19, 2009.

By the Office of Thrift Supervision.

Deborah Dakin,

Acting Chief Counsel.

[FR Doc. E9–12225 Filed 5–22–09; 8:45 am]

BILLING CODE 6720–01–P

DEPARTMENT OF VETERANS AFFAIRS

[OMB Control No. 2900–New (21–0842)]

Proposed Information Collection (Pre-Discharge Compensation Claim) Activity: Comment Request

AGENCY: Veterans Benefits Administration, Department of Veterans Affairs.

ACTION: Notice.

SUMMARY: The Veterans Benefits Administration (VBA), Department of Veterans Affairs (VA), is announcing an opportunity for public comment on the proposed collection of certain information by the agency. Under the Paperwork Reduction Act (PRA) of 1995, Federal agencies are required to publish notice in the **Federal Register** concerning each proposed collection of information, including each proposed new collection, and allow 60 days for public comment in response to the notice. This notice solicits comments on the information required from service members to participate in the pre-discharge claims program.

DATES: Written comments and recommendations on the proposed collection of information should be received on or before July 27, 2009.

ADDRESSES: Submit written comments on the collection of information through Federal Docket Management System (FDMS) at *http://www.Regulations.gov* or to Nancy J. Kessinger, Veterans Benefits Administration (20M35), Department of Veterans Affairs, 810 Vermont Avenue, NW., Washington, DC 20420 or e-mail to *nancy.kessinger@va.gov.* Please refer to ''OMB Control No. 2900–New (21–0842)'' in any correspondence. During the comment period, comments may be viewed online through FDMS.

FOR FURTHER INFORMATION CONTACT: Nancy J. Kessinger at (202) 461–9769 or FAX (202) 275–5947.

SUPPLEMENTARY INFORMATION: Under the PRA of 1995 (Pub. L. 104–13; 44 U.S.C. 3501–3521), Federal agencies must obtain approval from the Office of Management and Budget (OMB) for each collection of information they conduct or sponsor. This request for comment is being made pursuant to Section 3506(c)(2)(A) of the PRA.

With respect to the following collection of information, VBA invites comments on: (1) Whether the proposed collection of information is necessary for the proper performance of VBA's functions, including whether the information will have practical utility; (2) the accuracy of VBA's estimate of the burden of the proposed collection of information; (3) ways to enhance the quality, utility, and clarity of the information to be collected; and (4) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or the use of other forms of information technology.

Title: Pre-Discharge Compensation Claim, VA Form 21–0842.

OMB Control Number: 2900–New (21–0842).

Type of Review: New collection.

Abstract: The Pre-Discharge Compensation Claim form will be used by service members to file claims under the Benefits Delivery at Discharge or Quick Start programs under Title 38 U.S.C. 5101 (a). VA will use the data collected as the required certification statement needed from claimants to confirm that the information they provided is true and correct.

Affected Public: Individuals or households.

Estimated Annual Burden: 40,250.

Estimated Average Burden per Respondent: 15 minutes.

Frequency of Response: On occasion.

Estimated Number of Respondents: 161,000.

By direction of the Secretary.

Denise McLamb,

Program Analyst, Enterprise Records Service.

[FR Doc. E9–12301 Filed 5–22–09; 8:45 am]

BILLING CODE P

Tuesday,
May 26, 2009

Part II

Environmental Protection Agency

40 CFR Part 80

Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 80

[EPA–HQ–OAR–2005–0161; FRL–8903–1]

RIN 2060–A081

Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of proposed rulemaking.

SUMMARY: Under the Clean Air Act, as amended by Sections 201, 202, and 210 of the Energy Independence and Security Act of 2007, the Environmental Protection Agency is required to promulgate regulations implementing changes to the Renewable Fuel Standard program. The revised statutory requirements specify the volumes of cellulosic biofuel, biomass-based diesel, advanced biofuel, and total renewable fuel that must be used in transportation fuel each year, with the volumes increasing over time. The revised statutory requirements also include new definitions and criteria for both renewable fuels and the feedstocks used to produce them, including new greenhouse gas emission thresholds for renewable fuels. For the first time in a regulatory program, an assessment of greenhouse gas emission performance is being utilized to establish those fuels that qualify for the four different renewable fuel standards. As mandated by the revised statutory requirements, the greenhouse gas emission assessments must evaluate the full lifecycle emission impacts of fuel production including both direct and indirect emissions, including significant emissions from land use changes. The proposed program is expected to reduce U.S. dependence on foreign sources of petroleum by increasing domestic sources of energy. Based on our lifecycle analysis, we believe that the expanded use of renewable fuels would provide significant reductions in greenhouse gas emissions such as carbon dioxide that affect climate change. We recognize the significance of using lifecycle greenhouse gas emission assessments that include indirect impacts such as emission impacts of indirect land use changes. Therefore, in this preamble we have been transparent in breaking out the various sources of greenhouse gas emissions included in the analysis and are seeking comments on our methodology as well as various options for determining the lifecycle greenhouse gas emissions (GHG) for each fuel. In addition to seeking comments on the information in this document and its supporting materials, the Agency is conducting peer reviews of critical aspects of the lifecycle methodology. The increased use of renewable fuels would also impact criteria pollutant emissions, with some pollutants such as volatile organic compounds (VOC) and nitrogen oxides (NO_X) expected to increase and other pollutants such as carbon monoxide (CO) and benzene expected to decrease. The production of feedstocks used to produce renewable fuels is also expected to impact water quality.

This action proposes regulations designed to ensure that refiners, blenders, and importers of gasoline and diesel would use enough renewable fuel each year so that the four volume requirements of the Energy Independence and Security Act would be met with renewable fuels that also meet the required lifecycle greenhouse gas emissions performance standards. Our proposed rule describes the standards that would apply to these parties and the renewable fuels that would qualify for compliance. The proposed regulations make a number of changes to the current Renewable Fuel Standard program while retaining many elements of the compliance and trading system already in place.

DATES: Comments must be received on or before July 27, 2009, 60 days after publication in the **Federal Register**. Under the Paperwork Reduction Act, comments on the information collection provisions are best assured of having full effect if the Office of Management and Budget (OMB) receives a copy of your comments on or before June 25, 2009, 30 days after date of publication in the **Federal Register**.

Hearing: We will hold a public hearing on June 9, 2009 at the Dupont Hotel in Washington, DC. The hearing will start at 10 a.m. local time and continue until everyone has had a chance to speak. If you want to testify at the hearing, notify the contact person listed under **FOR FURTHER INFORMATION CONTACT** by June 1, 2009.

Workshop: We will hold a workshop on June 10–11, 2009 at the Dupont Hotel in Washington, DC to present details of our lifecycle GHG analysis. During this workshop, we intend to go through the lifecycle GHG analysis included in this proposal. The intent of this workshop is to help ensure a full understanding of our lifecycle analysis, the major issues identified and the options discussed. We expect that this workshop will help ensure that we receive submission of the most thoughtful and useful comments to this proposal and that the best methodology and assumptions are used for calculating GHG emissions impacts of fuels for the final rule. While this workshop will be held during the comment period, it is not intended to replace either the formal public hearing or the need to submit comments to the docket.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2005–0161, by one of the following methods:

- *www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *E-mail: asdinfo@epa.gov.*
- *Mail:* Air and Radiation Docket and Information Center, Environmental Protection Agency, *Mailcode:* 2822T, 1200 Pennsylvania Ave., NW., Washington, DC 20460. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), *Attn:* Desk Officer for EPA, 725 17th St., NW., Washington, DC 20503.
- *Hand Delivery:* EPA Docket Center, EPA West Building, Room 3334, 1301 Constitution Ave., NW., Washington, DC 20004. 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–OAR–2005–0161. 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 additional instructions on submitting comments, go to Section XI, Public Participation, of the **SUPPLEMENTARY INFORMATION** section of this document.

Docket: All documents in the docket are listed in the www.regulations.gov index. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in www.regulations.gov or in hard copy at the Air and Radiation Docket and Information Center, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

Hearing: The public hearing will be held on June 9, 2009 at the Dupont Hotel, 1500 New Hampshire Avenue, NW., Washington, DC 20036. See Section XI, Public Participation, for more information about the public hearing.

FOR FURTHER INFORMATION CONTACT: Julia MacAllister, Office of Transportation and Air Quality, Assessment and Standards Division, Environmental Protection Agency, 2000 Traverwood Drive, Ann Arbor, MI 48105; Telephone number: 734–214–4131; *Fax number:* 734–214–4816; *E-mail address: macallister.julia@epa.gov,* or Assessment and Standards Division Hotline; telephone number (734) 214–4636; E-mail address *asdinfo@epa.gov.*

SUPPLEMENTARY INFORMATION:

General Information

A. Does This Proposal Apply to Me?

Entities potentially affected by this proposal are those involved with the production, distribution, and sale of transportation fuels, including gasoline and diesel fuel or renewable fuels such as ethanol and biodiesel. Regulated categories include:

Category	NAICS[1] codes	SIC[2] codes	Examples of potentially regulated entities
Industry	324110	2911	Petroleum Refineries.
Industry	325193	2869	Ethyl alcohol manufacturing.
Industry	325199	2869	Other basic organic chemical manufacturing.
Industry	424690	5169	Chemical and allied products merchant wholesalers.
Industry	424710	5171	Petroleum bulk stations and terminals.
Industry	424720	5172	Petroleum and petroleum products merchant wholesalers.
Industry	454319	5989	Other fuel dealers.

[1] North American Industry Classification System (NAICS).
[2] Standard Industrial Classification (SIC) system code.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this proposed action. This table lists the types of entities that EPA is now aware could potentially be regulated by this proposed action. Other types of entities not listed in the table could also be regulated. To determine whether your activities would be regulated by this proposed action, you should carefully examine the applicability criteria in 40 CFR part 80. If you have any questions regarding the applicability of this proposed action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

B. What Should I Consider as I Prepare My Comments for EPA?

1. Submitting CBI

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

2. Tips for Preparing Your Comments

When submitting comments, remember to:

- Explain your views as clearly as possible.
- Describe any assumptions that you used.
- Provide any technical information and/or data you used that support your views.
- If you estimate potential burden or costs, explain how you arrived at your estimate.
- Provide specific examples to illustrate your concerns.
- Offer alternatives.
- Make sure to submit your comments by the comment period deadline identified.
- To ensure proper receipt by EPA, identify the appropriate docket identification number in the subject line on the first page of your response. It would also be helpful if you provided the name, date, and **Federal Register** citation related to your comments.

We are primarily seeking comment on the proposed 40 CFR Part 80 Subpart M regulatory language that is not directly included in 40 CFR Part 80 Subpart K. For the proposed subpart M regulatory language that is unchanged from subpart K, we are only soliciting comment as it relates to its use for the RFS2 rule.

Outline of This Preamble

I. Introduction

The current Renewable Fuel Standard program (RFS1) was originally adopted by EPA to implement the provisions of the Energy Policy Act of 2005 (EPAct), which added section 211(o) to the Clean Air Act (CAA). With the passage of the Energy Independence and Security Act of 2007 (EISA), Congress recently made several important revisions to these renewable fuel requirements. This Notice proposes to revise the RFS program regulations to implement these EISA provisions. The proposed changes would apply starting January 1, 2010. For the remainder of 2009, the current RFS1 regulations would apply. However, in anticipation of the biomass-based diesel standard proposed for 2010, obligated parties may find it in their best interest to plan accordingly in 2009.

A. Renewable Fuels and the Transportation Sector

For the past several years, U.S. renewable fuel use has been rapidly increasing for a number of reasons. In the early 1990's, certain oxygenated gasoline fuel programs required by the CAA amendments of 1990 established new market opportunities for renewable fuels, primarily ethanol. At the same time, growing concern over U.S. dependence on foreign sources of crude placed increasing focus on renewable fuels as a replacement for petroleum-based fuels. More recently, several state bans on the use of methyl tertiary butyl ether (MTBE) in gasoline resulted in a large, sudden increase in demand for ethanol. Perhaps the largest impact on renewable fuel demand, however, has been the dramatic increase in the cost of crude oil. In the last few years, both crude oil prices and crude oil price forecasts have increased dramatically, which have resulted in a large economic incentive for the increased development and use of renewable fuels.

In 2005, Congress introduced a new approach to supporting renewable fuels. EPAct established a major new federal renewable fuel volume mandate. EPAct required a ramp up to 7.5 billion gallons of renewable fuel as motor vehicle fuel by 2012 and set annual volume targets for each year leading up to 2012. For 2013 and beyond, EPA was directed to establish the annual required renewable fuel volumes, but at a percentage level no less than that required for 2012. While the market forces described above ultimately caused renewable fuel use to far exceed the EPAct mandates, this program provided certainty that at least a minimum amount of renewable fuel would be used in the U.S. transportation market, which in turn provided assurance for investment in production capacity.

The subsequent passage of EISA made significant changes to both the structure and the magnitude of the renewable fuel program. The renewable fuel program established by EISA, hereafter referred to as RFS2, mandates the use of 36 billion gallons of renewable fuel by 2022. This is nearly a five-fold increase over the highest volume specified by EPAct and constitutes a 10-year extension of the scheduled production ramp-up period provided for in that legislation. It is clear that the volumes required by EISA will push the market to new levels—far beyond what current market conditions would achieve alone. In addition, EISA specifies four separate categories of renewable fuels, each with a separate volume mandate. The categories are renewable fuel, advanced biofuel, biomass-based diesel, and cellulosic biofuel. There is a notable increase in the mandate for cellulosic biofuels in particular. EISA increased the cellulosic biofuel mandate from 250 million in EPAct to 1.0 billion gallons by 2013, with additional yearly increases to 16 billion gallons by 2022. These requirements will provide a strong foundation for investment in cellulosic production and position cellulosic fuel to become a major portion of the renewable fuel pool over the next decade.

The implications of the volume expansion of the program are not trivial. Development of infrastructure capable of delivering, storing and blending these volumes in new markets and expanding existing market capabilities will be needed. For example, the market's absorption of increased volumes of ethanol may ultimately require new ''outlets'' beyond E10 blends (i.e., gasoline containing 10% ethanol by volume), such as an expansion of the number of flexible-fuel E85 vehicles and the number of retail outlets selling E85.

B. Renewable Fuels and Greenhouse Gas Emissions

Another significant aspect of the RFS2 program is the focus on the greenhouse gas impact of renewable fuels, from a lifecycle perspective. The lifecycle GHG emissions means the aggregate quantity of GHGs related to the full fuel cycle, including all stages of fuel and feedstock production and distribution, from feedstock generation and extraction through distribution and delivery and use of the finished fuel. EISA established specific greenhouse gas emission thresholds for each of four types of renewable fuels, requiring a percentage improvement compared to a baseline of the gasoline and diesel used in 2005. EPA must conduct a lifecycle analysis to determine whether or not renewable fuels produced under varying conditions will meet the greenhouse gas (GHG) thresholds for the different fuel types for which EISA establishes mandates. While these thresholds do not constitute a control on greenhouse gases for transportation fuels (such as a low carbon fuel standard),[1] they do require that the volume mandates be met through the use of renewable fuels that meet certain lifecycle GHG reduction thresholds when compared to

[1] *See* Section IV.D of EPA's advanced notice of proposed rulemaking, Regulating Greenhouse Gas Emissions under the Clean Air Act, for a discussion of EPA's possible authority under section 211(c) of the CAA to establish GHG standards for renewable and alternative fuels. 73 FR 44354, July 30, 2008.

the baseline lifecycle emissions of petroleum fuel they replace. Compliance with the thresholds requires a comprehensive evaluation of renewable fuels, as well as of gasoline and diesel, on the basis of their lifecycle emissions. As mandated by EISA, the greenhouse gas emission assessments must evaluate the full lifecycle emission impacts of fuel production including both direct and indirect emissions, including significant emissions from land use changes. We recognize the significance of using lifecycle greenhouse gas emission assessments that include indirect impacts such as emission impacts of indirect land use changes. Therefore, in this preamble, we have been transparent in breaking out the various sources of greenhouse gas emissions included in the analysis. As described in detail in Section VI, EPA has analyzed the lifecycle GHG impacts of the range of biofuels currently expected to contribute significantly to meeting the volume mandates of EISA through 2022. In these analyses we have used the best science available. Our analysis relies on peer reviewed models and the best estimate of important trends in agricultural practices and fuel production technologies as these may impact our prediction of individual biofuel GHG performance through 2022. We have identified and highlighted assumptions and model inputs that particularly influence our assessment and seek comment on these assumptions, the models we have used and our overall methodology so as to assure the most robust assessment of lifecycle GHG performance for the final rule.

Because lifecycle analysis is a new part of the RFS program, in addition to the formal comment period on the proposed rule, EPA is making multiple efforts to solicit public and expert feedback on our proposed approach. EPA plans to hold a public workshop focused specifically on lifecycle analysis during the comment period to assure full understanding of the analyses conducted, the issues addressed and the options that are discussed. We expect that this workshop will help ensure that we receive submission of the most thoughtful and useful comments to this proposal and that the best methodology and assumptions are used for calculating GHG emissions impacts of fuels for the final rule. Additionally, between this proposal and the final rule, we will conduct peer-reviews of key components of our analysis. As explained in more detail in the Section VI, EPA is specifically seeking peer review of: Our use of satellite data to project future the type of land use changes; the land conversion GHG emissions factors estimates we have used for different types of land use; our estimates of GHG emissions from foreign crop production; methods to account for the variable timing of GHG emissions; and how the several models we have relied upon are used together to provide overall lifecycle GHG estimates.

In addition to the GHG thresholds, EISA included several provisions for the RFS2 program designed to address the long-term environmental sustainability of expanded biofuels production. The new law limits the crops and crop residues used to produce renewable fuel to those grown on land cleared or cultivated at any time prior to enactment of EISA, that is either actively managed or fallow, and non-forested. EISA also generally requires that forest-related slash and tree thinnings used for renewable fuel production pursuant to the Act be harvested from non-federal forest lands.

To address potential air quality concerns, EPA is required by section 209 of EISA to determine whether the RFS2 volumes will adversely impact air quality as a result of changes in vehicle and engine emissions and then to issue fuel regulations that mitigate—to the extent achievable—these impacts. The Agency is also required by section 204 of EISA to conduct a broad study of environmental and resource conservation impacts of EISA, including impacts on water quality and availability, soil conservation, and biodiversity. Congress set specific deadlines for both of these provisions, which are separate from this rulemaking and will be carried out as part of a future effort. However, this NPRM does include EPA's initial assessment of the air and water quality impacts of the EISA volumes.

While the above described changes are significant, it is important to note that Congress left other structural elements of the RFS program basically intact. The various modifications are discussed throughout this preamble.

C. Building on the RFS1 Program

In designing this proposed RFS2 program, the Agency is utilizing and building on the same programmatic structure created to implement the current renewable fuel program (hereafter referred to as RFS1). For example, we propose to continue to use the Renewable Identification Number (RIN) system currently in place to track compliance with the RFS1 program, with modifications to implement the EISA provisions. This approach is in keeping with the Agency's overall intent for RFS1—to design a flexible and enforceable system that could continue to operate effectively regardless of the level of renewable fuel use or market conditions in the transportation fuel sector.

A key component of the Agency's work to build a successful RFS1 program was early and sustained engagement with our stakeholders. In developing this proposed rulemaking, we have again worked closely with a wide variety of stakeholders. Because EISA created new obligated parties and established new, complex provisions such as the lifecycle GHG thresholds and previous cropland requirements, EPA has extended its stakeholder engagement to include dozens of meetings with stakeholders from a broad spectrum of perspectives. For example, the Agency has had multiple meetings and discussions with renewable fuel producers, technology companies, petroleum refiners and importers, agricultural associations, lifecycle experts, environmental groups, vehicle manufacturers, states, gasoline and petroleum marketers, pipeline owners and fuel terminal operators.

II. Overview of the Proposed Program

This section provides an overview of the RFS2 program requirements that EPA proposes to implement as a result of EISA. The RFS2 program would replace the RFS1 program promulgated on May 1, 2007 (72 FR 23900).[2] We are also proposing a number of changes to make the program more flexible based on what we learned from the operation of the RFS1 program since it began on September 1, 2007. Details of the proposed requirements can be found in Sections III and IV. We request comment on our proposed regulatory requirements and the alternatives that we have considered.

This section also provides a summary of EPA's impacts assessment of the use of higher renewable fuel volumes. Impacts that we assessed include: emissions of pollutants such as greenhouse gases (GHG), oxides of nitrogen (NO_X), hydrocarbons, particulate matter (PM), and toxics; reductions in petroleum use and related impacts on national energy security; impacts on the agriculture sector; impacts on costs of transportation fuels; economic costs and benefits; and impacts on water. Details of these

[2] To meet the requirements of EPAct, EPA had previously adopted a limited program that applied only to calendar year 2006. The RFS1 program refers to the general program adopted in the May 2007 rulemaking.

analyses can be found in Sections V through X and in the Draft Regulatory Impact Analysis (DRIA).

A. Summary of New Provisions of the RFS Program

Today's notice proposes new regulatory requirements for the RFS program that would be implemented through a new Subpart M to 40 CFR Part 80. EPA is generally proposing to maintain many elements of the RFS1 program such as regulations governing the generation, transfer, and use of Renewable Identification Numbers (RINs). At the same time, we seek comment on a number of RFS1 provisions that may require adjustment under an expanded RFS2 program, including whether or not to require that all qualifying renewable fuels have RINs generated for it (discussed in Section III.B.4.b.ii), and whether a rollover cap on RINs other than 20 percent might be appropriate (discussed in Section IV.D). Furthermore, EPA is proposing several new provisions and seeking comment on alternatives on aspects of the program for which EISA grants EPA discretion and flexibility, such as the grandfathering of existing renewable fuel production facilities (discussed in Section III.B.3), the potential inclusion of electricity for credit (discussed in Section III.B.1.a), and how renewable fuels are categorized based on the results of lifecycle analyses (discussed in Section VI.B). We believe these and other aspects of the program are important because they will affect available volumes of qualifying renewable fuel, regulated parties' ability to comply with the program and, ultimately, the program's environmental and societal impacts. A full description of all the changes we are proposing to the RFS program to implement the requirements in EISA is provided in Section III, while Section IV includes extensive discussion of other changes to the RFS program under consideration.

1. Required Volumes of Renewable Fuel

The primary purpose of the RFS program is to require a minimum volume of renewable fuel to be used each year in the transportation sector. Under RFS1, the required volume was 4.0 billion gallons in 2006, ramping up to 7.5 billion gallons by 2012. Starting in 2013, EPAct required that the total volume of renewable fuel represent at minimum the same volume fraction of the gasoline fuel pool as it did in 2012, and that the total volume of renewable fuel contains at least 250 million gallons of fuel derived from cellulosic biomass.

EISA makes three primary changes to the volume requirements of the RFS program. First, it substantially increases the required volumes and extends the timeframe over which the volumes ramp up through at least 2022. Second, it divides the total renewable fuel requirement into four separate categories, each with its own volume requirement. Third, it requires that each of these mandated volumes of renewable fuels achieve certain minimum thresholds of GHG emission performance. The volume requirements in EISA are shown in Table II.A.1–1.

TABLE II.A.1–1—RENEWABLE FUEL VOLUME REQUIREMENTS FOR RFS2

[Billion gallons]

	Cellulosic biofuel requirement	Biomass-based diesel requirement	Advanced biofuel requirement	Total renewable fuel requirement
2009	n/a	0.5	0.6	11.1
2010	0.1	0.65	0.95	12.95
2011	0.25	0.80	1.35	13.95
2012	0.5	1.0	2.0	15.2
2013	1.0	[a]	2.75	16.55
2014	1.75	[a]	3.75	18.15
2015	3.0	[a]	5.5	20.5
2016	4.25	[a]	7.25	22.25
2017	5.5	[a]	9.0	24.0
2018	7.0	[a]	11.0	26.0
2019	8.5	[a]	13.0	28.0
2020	10.5	[a]	15.0	30.0
2021	13.5	[a]	18.0	33.0
2022	16.0	[a]	21.0	36.0
2023+	[b]	[b]	[b]	[b]

[a] To be determined by EPA through a future rulemaking, but no less than 1.0 billion gallons.
[b] To be determined by EPA through a future rulemaking.

As shown in the table, the volume requirements are not exclusive, and generally result in nested requirements. Any renewable fuel that meets the requirement for cellulosic biofuel or biomass-based diesel is also valid for meeting the advanced biofuel requirement. Likewise, any renewable fuel that meets the requirement for advanced biofuel is also valid for meeting the total renewable fuel requirement. *See* Section VI.E for further discussion of which specific types of fuel meet the requirements for one of the four categories shown in Table II.A.1–1.

We are co-proposing and taking comment on two options for how to treat the volumes of different renewable fuels for purposes of complying with the volume mandates of RFS2: As either ethanol-equivalent gallons, based on energy content, as finalized in the RFS1 program, or as actual volume in gallons. Consideration of the actual volume option would recognize that EISA now guarantees a market for specific categories of renewable fuel and assigns a GHG requirement to each category in the form of minimum GHG thresholds that each must meet. The approach taken in RFS1 would continue to assign value, in terms of gallons, to all renewable fuels based on their energy value in comparison with ethanol. Further discussion of the rationale and implications of these two approaches can be found in Section III.D.1.

The statutorily-prescribed phase-in period ends in 2012 for biomass-based diesel and in 2022 for cellulosic biofuel, advanced biofuel, and total renewable fuel. Beyond these years, EISA requires EPA to determine the applicable volumes based on a review of the implementation of the program up to that time, and an analysis of a wide variety of factors such as the impact of the production of renewable fuels on the environment, energy security, infrastructure, costs, and other factors. For these future standards, EPA must promulgate rules establishing the applicable volumes no later than 14 months before the first year for which such applicable volumes would apply. For biomass-based diesel, this would mean that final rules would need to be issued by October 31, 2011 for application starting on January 1, 2013. In today's proposed rulemaking, we are not suggesting any specific volume requirements for biomass-based diesel for 2013 and beyond that would be appropriate under the statutory criteria that we must consider. Likewise, we are not suggesting any specific volume requirements for the other three renewable fuel categories for 2023 and beyond. However, the statute requires that the biomass-based diesel volume in 2013 and beyond must be no less than 1.0 billion gallons, and that advanced biofuels in 2023 and beyond must represent at a minimum the same percentage of total renewable fuel as it does in 2022.

2. Changes in How Renewable Fuel Is Defined

Under the existing Renewable Fuel Standard, (RFS1) renewable fuel is defined generally as ''any motor vehicle fuel that is used to replace or reduce the quantity of fossil fuel present in a fuel mixture used to fuel a motor vehicle''. The RFS1 definition includes motor vehicle fuels produced from biomass material such as grain, starch, fats, greases, oils and biogas.

The definitions of renewable fuels under today's proposed rule (RFS2) are based on the new statutory definitions in EISA. Like the existing rules, the definitions in RFS2 include a general definition of renewable fuel, but unlike RFS1, we are including a separate definition of ''Renewable Biomass'' which identifies the feedstocks from which renewable fuels may be made.

Another difference in the definitions of renewable fuel is that RFS2 contains three subcategories of renewable fuels: (1) Advanced Biofuel, (2) Cellulosic Biofuel and (3) Biomass-Based Diesel.

''Advanced Biofuel'' is a renewable fuel other than ethanol derived from corn starch and which must achieve a lifecycle GHG emission displacement of 50%, compared to the gasoline or diesel fuel it displaces.

Cellulosic biofuel is any renewable fuel, not necessarily ethanol, derived from any cellulose, hemicellulose, or lignin each of which must originate from renewable biomass. It must achieve a lifecycle GHG emission displacement of 60%, compared to the gasoline or diesel fuel it displaces for it to qualify as cellulosic biofuel.

The RFS1 definition provided that ethanol made at any facility—regardless of whether cellulosic feedstock is used or not—may be defined as cellulosic if at such facility ''animal wastes or other waste materials are digested or otherwise used to displace 90% or more of the fossil fuel normally used in the production of ethanol.'' This provision was not included in EISA, and therefore does not appear in the definitions pertaining to cellulosic biofuel in today's proposed rule.

The statutory definition of ''renewable biomass'' in EISA does not include a reference to municipal solid waste (MSW) as did the definition of ''cellulosic biomass ethanol'' in EPAct, but instead includes ''separated yard waste and food waste. EPA's proposed definition of renewable biomass in today's proposed rule includes the language present in EISA. As discussed in Section III.B.1.a, we invite comment on whether this definition should be interpreted as including or excluding MSW containing yard and/or food waste from the definition of renewable biomass. EPA intends to resolve this matter in the final rule, and EPA solicits comment on the approach that it should take.

Under today's proposed rule ''Biomass-based diesel'' includes biodiesel (mono-alkyl esters), non-ester renewable diesel and any other diesel fuel made from renewable biomass, as long as they are not ''co-processed'' with petroleum. EISA requires that such fuel achieve a lifecycle GHG emission displacement of 50%, compared to the gasoline or diesel fuel it displaces. As discussed in Section III.B.1.d, we are proposing that co-processing is considered to occur only if both petroleum and biomass feedstock are processed in the same unit simultaneously. Thus, if serial batch processing in which 100% vegetable oil is processed one day/week/month and 100% petroleum the next day/week/month occurs, the fuel derived from renewable biomass would be assigned RINs with a D code identifying it as biomass-based diesel. The resulting products could be blended together, but only the volume produced from renewable biomass would count as biomass-based diesel.

For other renewable fuels, EISA makes a distinction between fuel from new and existing facilities. Only renewable fuel from new facilities is required to achieve a lifecycle GHG emission displacement of 20%. As discussed in Section III.B.3, this requirement applies only to renewable fuel that is produced from certain facilities which commenced construction after December 19, 2007.

EISA defines ''additional renewable fuel'' as fuel produced from renewable biomass that is used to replace or reduce fossil fuels used in home heating oil or jet fuel. The Act provides that EPA may allow for the generation of RFS credits for such fuel. This represents a change from RFS1, where renewable fuel qualifying for credits was limited to fuel used in motor vehicles. We propose to modify the regulatory requirements to allow RINs assigned to renewable fuel blended into heating oil or jet fuel to be valid for compliance purposes. The fuel would still have to meet all the other criteria to qualify as a renewable fuel, including being made from renewable biomass. For example, RINs generated for advanced biofuel or biomass-based diesel that could be used in automobiles would still be valid, and would not need to be retired, if the fuel producer instead sells the fuels for use in heating oil or jet fuel.

''Renewable biomass'' is defined in EISA to include a number of feedstock types, such as planted crops and crop residue, planted trees and tree residue, animal waste, algae, and yard and food waste. However, the EISA definition limits many of these feedstocks according to the management practices for the land from which they are derived. For example, planted crops and crop residue must be harvested from agricultural land cleared or cultivated at any time prior to December 19, 2007, that is actively managed or fallow, and non-forested. Therefore, planted crops and crop residue derived from land that does not meet this definition cannot be used to produce renewable fuel for credit under RFS2.

Under today's proposed rule, we describe several options for ensuring that feedstocks used to produce renewable fuel for which credits are generated under RFS2 meet the definition of renewable biomass. Our proposed approach places overall responsibility for verifying a feedstock's source on the party who generates a RIN for the renewable fuel produced from the feedstock. We also present options for how a party could or should verify his or her feedstock, and we seek comment on these options. A full discussion of the definition and implementation options for ''renewable biomass'' is presented in Section III.B.4.

3. Analysis of Lifecycle Greenhouse Gas Emissions and Thresholds for Renewable Fuels

As shown in Table II.A.3–1, EISA requires that a renewable fuel must meet minimum thresholds for their reduction in lifecycle greenhouse gas emissions: A 20% reduction in lifecycle GHG emissions for any renewable fuel produced at new facilities; a 50% reduction in order to be classified as biomass-based diesel or advanced biofuel; and a 60% reduction in order to be classified as cellulosic biofuel. The lifecycle GHG emissions means the aggregate quantity of GHG emissions related to the full fuel cycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through distribution and delivery and use of the finished fuel. As mandated by EISA, it includes direct emissions and significant indirect emissions such as significant emissions from land use changes. EPA believes that compliance with the EISA mandate—determining the aggregate GHG emissions related to the full fuel lifecycle, including both direct emissions and significant indirect emissions such as land use changes—make it necessary to assess those direct and indirect impacts that occur not just within the United States but also those that occur in other countries. This applies to determining the lifecycle emissions for petroleum-based fuels to determine the baseline, as well as the lifecycle emissions for biofuels. For biofuels, this includes evaluating significant emissions from indirect land use changes that occur in other countries as a result of the increased domestic production or importation of biofuels into the U.S. As detailed in Section VI, we have included the GHG emission impacts of international land use changes including the indirect land use changes that result from domestic production of biofuel feedstocks. We recognize the significance of including international land use emission impacts and, in our analysis presentation in Section VI, have been transparent in breaking out the various sources of GHG emissions so that the reader can readily see the impact of including international land use impacts.

TABLE II.A.3–1—LIFECYCLE GHG THRESHOLDS SPECIFIED IN EISA

[Percent reduction from baseline]

Renewable fuel [a]	20
Advanced biofuel	50
Biomass-based diesel	50
Cellulosic biofuel	60

[a] The 20% criterion generally applies to renewable fuel from new facilities that commenced construction after December 19, 2007.

The lifecycle GHG emissions of the renewable fuel are compared to the lifecycle GHG emissions for gasoline or diesel (whichever is being replaced by the renewable fuel) sold or distributed as transportation fuel in 2005. EISA provides some limited flexibility for EPA to adjust these GHG percentage thresholds downward by up to 10 percent under certain circumstances. As discussed in Section VI.D, we are proposing that the GHG threshold for advanced biofuels be adjusted to 44% or potentially as low as 40% depending on the results from the analyses that will be conducted for the final rule. This adjustment would allow ethanol produced from sugarcane to count as advanced biofuel and would help ensure that the volume mandate for advanced biofuel could be met.

The regulatory purpose of the lifecycle greenhouse gas emissions analysis is to determine whether renewable fuels meet the GHG thresholds for the different categories of renewable fuel. As described in detail in Section VI, EPA has analyzed the lifecycle GHG impacts of the range of biofuels currently expected to contribute significantly to meeting the volume mandates of EISA through 2022. In these analyses we have used the best science available. Our analysis relies on peer reviewed models and the best estimate of important trends in agricultural practices and fuel production technologies as these may impact our prediction of individual biofuel GHG performance through 2022. We have identified and highlighted assumptions and model inputs that particularly influence our assessment and seek comment on these assumptions, the models we have used and our overall methodology so as to assure the most robust assessment of lifecycle GHG performance for the final rule.

In addition to the many technical issues addressed in this proposal, Section VI discusses the emissions decreases and increases associated with the different parts of the lifecycle emissions of various biofuels and the timeframes in which these emissions changes occur. The need to determine a single lifecycle value that best represents this combination of emissions increases and decreases occurring over time led EPA to consider various alternative ways to analyze the timeframe of emissions changes related to biofuel production and use as well as options for adjusting or discounting these emissions to determine their net present value. Section VI highlights two options. One option assumes a 30 year time period for assessing future GHG emissions impacts of the anticipated increase in biofuel production to meet the mandates of EISA, both emissions increases and decreases, and values all these emission impacts the same regardless of when they occur during that time period (i.e., no discounting). The second option assesses emissions impacts over a 100 year time period but then discounts future emissions 2% annually to arrive at an estimate of a net present value of those emissions. Several other variations of time period and discount rate are also discussed. The analytical time horizon and the choice whether to discount GHG emissions and, if so, at what appropriate rate can have a significant impact on the final assessment of the lifecycle GHG emissions impacts of individual biofuels as well as the overall GHG impacts of these EISA provisions and this rule.

We believe that our lifecycle analysis is based on the best available science and recognize that in some aspects it represents a cutting edge approach to addressing lifecycle GHG emissions. Because of the varying degrees of uncertainty in the different aspects of our analysis, we conducted a number of sensitivity analyses which focus on key parameters and demonstrate how our assessments might change under alternative assumptions. By focusing attention on these key parameters, the comments we receive as well as additional investigation and analysis by EPA will allow narrowing of uncertainty concerns for the final rule. In addition to this sensitivity analysis approach, we will also explore options for more formal uncertainty analyses for the final rule to the extent possible.

Because lifecycle analysis is a new part of the RFS program, in addition to the formal comment period on the proposed rule, EPA is making multiple efforts to solicit public and expert feedback on our proposed approach. EPA plans to hold a public workshop focused specifically on lifecycle analysis during the comment period to assure full understanding of the analyses conducted, the issues addressed and the options that are discussed. We expect that this workshop will help ensure that we receive submission of the most thoughtful and useful comments to this proposal and that the best methodology and assumptions are used for calculating GHG emissions impacts of fuels for the final rule. Additionally, between this proposal and the final rule, we will conduct peer reviews of key components of our analysis. As explained in more detail in Section VI, EPA is specifically seeking peer review of: Our use of satellite data to project future types of land use changes; the land conversion GHG emissions factors estimates we have used for different types of land use; our estimates of GHG emissions from foreign crop production; methods to account for the variable timing of GHG emissions; and how the several models we have relied upon are used together to provide overall lifecycle GHG estimates.

Some renewable fuel is not required to meet the 20% GHG threshold. Section 211(o)(2)(A) provides that only renewable fuel produced from new facilities which commenced construction after December 19, 2007 must meet the 20% threshold. Facilities that commenced construction on or before December 19, 2007 are exempt or ''grandfathered'' from the 20% threshold requirement. In addition, section 210(a) of EISA provides a further exemption from the 20% threshold requirement for ethanol plants that commenced construction in 2008 or 2009 and are fired with natural gas, biomass, or any combination thereof. The renewable fuel from such facilities is deemed to be in compliance with the 20% threshold, and would thus also be ''grandfathered.''

We are proposing and taking comment on one approach to the grandfathering provisions in today's rule, and seeking comment on five additional options. The proposed approach would provide an indefinite time period for grandfathering status but with restrictions to the baseline volume of renewable fuel that is grandfathered. The alternative options are (1) Expiration of exemption for grandfathered status when facilities undergo sufficient changes to be considered ''reconstructed''; (2) Expiration of exemption 15 years after EISA enactment, industry-wide; (3) Expiration of exemption 15 years after EISA enactment with limitation of exemption to baseline volume; (4) ''Significant'' production components are treated as facilities and grandfathered or deemed compliant status ends when they are replaced; and (5) Indefinite exemption and no limitations placed on baseline volumes. Our proposal and the alternative options are discussed in further detail in Section III.B.3.c.

While renewable fuels would be required to meet the GHG thresholds shown in Table II.A.3–1 in order to be valid for compliance purposes under the RFS2 program, we are not proposing that an individual facility-specific lifecycle GHG emissions value would have to be determined in order to show that the biofuel produced or imported at an individual facility complies with the threshold. Instead, EPA has determined lifecycle GHG values for specific combinations of fuel type, feedstock, and production process, using average values for various lifecycle model inputs. As a result of these assessments, we propose to assign each combination of fuel type, feedstock, and production process to one of the four renewable fuel categories specified in EISA or, alternatively, make a determination that the biofuel combination has been disqualified from generating RINs (except as may be allowed for grandfathered renewable fuel) due to a failure to meet the minimum 20% GHG threshold. Section VI.E discusses our proposed assignments. We are also proposing a mechanism to allow biofuels whose lifecycle GHG emissions have not been assessed to participate in the RFS program under certain limited conditions. These conditions are described in Section III.D.5.

4. Coverage Expanded to Transportation Fuel, Including Diesel and Nonroad Fuels

EPAct only mandated the blending of renewable fuels into gasoline, though it gave credit for renewable fuels blended into diesel fuel. EISA expanded the program to generally cover transportation fuel, which is defined as fuel for use in motor vehicles, motor vehicle engines, nonroad vehicles, or nonroad engines. This includes diesel fuel intended for use in highway vehicles and engines, and nonroad, locomotive, and marine engines and vessels, as well as gaseous or other fuels used in these vehicles, engines, or vessels. EISA also specifies that ''transportation fuels'' do not include fuels for use in ocean-going vessels.

EPA is required to ensure that transportation fuel contains at least the specified volumes of renewable fuel. Under EISA, renewable fuel now includes fuel that is used to displace fossil fuel present in transportation fuel, and as in RFS1, EPA is required to determine the refiners, blenders, and importers of transportation fuel that are subject to the renewable volume obligation. As discussed in Section III.F, while we are seeking comment on alternatives, EPA is proposing consistent with RFS1 that these provisions could best be met by requiring that the renewable volume obligation apply to refiners, blenders, and importers of motor vehicle or nonroad gasoline or diesel (with limited flexibilities for small refineries and small refiners), and that their percentage obligation would apply to the amount of gasoline or diesel they produce for such use. We propose to use the current definition of motor vehicle, nonroad, locomotive, and marine diesel fuel (MVNRLM)—as defined at § 80.2(qqq)—to determine the obligated volumes of non-gasoline transportation fuel for this rule.

We request comment on these aspects of our proposed program.

5. Effective Date for New Requirements

Under CAA section 211(o) as modified by EISA, EPA is required to revise the RFS1 regulations within one year of enactment, or December 19, 2008. Promulgation by this date would have been consistent with the revised volume requirements shown in Table II.A.1–1 that begin in 2009 for certain categories of renewable fuel. However, due to the addition of complex lifecycle assessments to the determination of eligibility of renewable fuels, the extensive analysis of impacts that we are conducting for the higher renewable fuel volumes, the various complex changes to the regulatory program that require close collaboration with stakeholders, and various statutory limitations such as the Small Business Regulatory Enforcement Flexibility Act (SBREFA) and a 60 day Congressional review period for all significant actions, we were not able to promulgate final RFS2 program requirements by December 19, 2008. As a result, we are proposing that the RFS2 regulatory program go into effect on January 1, 2010.

In order to successfully implement the RFS2 program, parties that generate RINs, own and/or transfer them, or use them for compliance purposes will need to re-register under the RFS2 provisions and modify their information technology (IT) systems to accommodate the changes we are proposing today. As described more fully in Section III, these changes would include redefining the D code within the RIN, adding a process for verifying that feedstocks meet the renewable biomass definition, and calculating compliance with four standards instead of one. Regulated parties will need to establish new contractual relationships to cover the different types of renewable fuel required under RFS2. Parties that produce MVNRLM diesel but not gasoline will be newly obligated parties and may be establishing IT systems for the RFS program for the first time. For RFS1, regulated parties had four months between promulgation of the final rulemaking on May 1, 2007 and the start of the program on September 1, 2007. However, this was for a new program that had not existed before. For the RFS2 program, most regulated parties will already be familiar with the general requirements for RIN generation, transfer, and use, and the attendant recordkeeping and reporting requirements. We believe that with proper attention to the implementation requirements by regulated parties, the RFS2 program can be implemented on January 1, 2010 following release of the final rule.

Although we are proposing that the RFS2 regulatory program begin on January 1, 2010, we seek comment on whether a start date later than January 1, 2010 would be necessary. Alternative effective dates for the RFS2 program include January 1, 2011 and a date after January 1, 2010 but before January 1, 2011. We are requesting comment on all issues related to such an alternative effective date, including the need for such a delayed start, treatment of diesel producers and importers, whether the standards for advanced biofuel, cellulosic biofuel and biomass-based diesel should apply to the entire 2010 production or just the production that would occur after the RFS2 effective date, and the extent to which RFS1 RINs should be valid to show compliance with RFS2 standards. Further discussion of alternative effective dates for RFS2 can be found in Section III.E.1.d.

6. Treatment of Required Volumes Preceding the RFS2 Effective Date

We are proposing that the RFS2 regulatory program begin on January 1, 2010. Under CAA section 211(o), the requirements for refiners, blenders, and importers (called ''obligated parties'') as well as the requirements for producers of renewable fuel and others, stem from the regulatory provisions adopted by EPA. In effect while EPAct and EISA both call for EPA to issue regulations that achieve certain results, the various regulated parties are not subject to these requirements until EPA issues the regulations establishing their obligations. The changes brought about by EISA, such as the 4 separate standards, the lifecycle GHG thresholds, changes to obligated parties, and the revised definition of renewable biomass do not become effective until today's proposal is finalized. Rather, the current RFS1 regulations continue to apply until EPA amends them to implement EISA, and any delay in issuance of the RFS2 regulations means that parties would continue to be subject to the RFS1 regulations until the RFS2 regulations were in effect. Therefore, regulated parties would continue to be subject to the existing regulations at 40 CFR Part 80 Subpart K through December 31, 2009, or later if the effective date of the RFS2 program were later than January 1, 2010.

Under the RFS1 regulations the annual percentage standards that are applicable to obligated parties are determined by a formula set forth in the regulations. The formula uses gasoline volume projections from the Energy Information Administration (EIA) and the required volume of renewable fuel provided in Clean Air Act section 211(o)(2)(B). Since EISA modified the required volumes in this section of the Clean Air Act, EPA believes that the new statutory volumes can be used under the RFS1 regulations in generating the standards for 2009. Therefore, in November 2008 we used the new total renewable fuel volume of 11.1 billion gallons as the basis for the 2009 standard, and not the 6.1 billion gallons that was required by EPAct.[3]

While this approach will ensure that the total renewable fuel volume of 11.1 billion gallons required by EISA for 2009 will be used, the RFS1 regulatory structure does not provide a mechanism for implementing the 0.5 billion gallon requirement for biomass-based diesel nor the 0.6 billion gallon requirement for advanced biofuel. As described in more detail in Section III.E.2, we are proposing to address this issue by increasing the 2010 biomass-based diesel requirement by 0.5 billion gallons and allowing 2009 biodiesel and renewable diesel RINs to be used to meet this combined 2009/2010 requirement. Doing so would also allow most of the 2009 advanced biofuel requirement to be met. We believe this would provide a similar incentive for biomass-based diesel use in 2009 as would have occurred had we been able to implement this standard for 2009. We propose that this requirement would apply to all obligated parties under RFS2, including producers and importers of diesel fuel.

As noted above, EPA is proposing a start date for the RFS2 program of January 1, 2010, and is also seeking comment on alternative start dates of sometime during 2010 or January 1, 2011. If the start date is other than January 1, 2010, EPA would need to determine what renewable fuel volumes to require in the interim between January 1, 2010 and the start of the RFS2 program. While we could apply the same approach, described above, that we have used for 2009, doing so could mean that 2009 biodiesel RINs would be valid for compliance purposes in 2011, which would run counter to the statutory valid life of two years. Nevertheless, we request comment on whether this potential approach or another approach is warranted based on the differing volumes and types of renewable fuel specified for use in EISA for 2010.

7. Waivers and Credits for Cellulosic Biofuel

Section 202(e) of EISA provides that for any calendar year in which the projected volume of cellulosic biofuel production is less than the minimum applicable volume required by the statute, EPA will waive a portion of the cellulosic biofuel standard by using the projected volume as the basis for setting the applicable standard. In this event, EISA also allows but does not require EPA to reduce the required volume of advanced biofuel and total renewable fuel. The process of projecting the volume of cellulosic biofuel that may be produced in the next year, and the associated process of determining whether and to what degree the advanced biofuel and total renewable fuel requirements should be lowered, will involve considerations that extend beyond the simple calculation based on gasoline demand that was used to set the annual standards under RFS1. As a result, we believe that this process should be subject to a notice-and-comment rulemaking process. Moreover, since we must make these determinations every year for application to the following year, we expect to conduct these rulemakings every year.

In determining whether the advanced biofuel and/or total renewable fuel volume requirements should also be adjusted downward in the event that projected volumes of cellulosic biofuel fall short of the statutorily required volumes, we believe it would be appropriate to allow excess advanced biofuels to make up some or all of the shortfall in cellulosic biofuel. For instance, if we determined that sufficient biomass-based diesel was available, we could decide that the required volume of advanced biofuel need not be lowered, or that it should be lowered to a smaller degree than the required cellulosic biofuel volume. We would then lower the total renewable fuel volume to the same degree that we

[3] 73 FR 70643, November 21, 2008.

would lower the advanced biofuel volume. We do not believe it would be appropriate to lower the advanced biofuel standard but not the total renewable standard, as this would allow conventional biofuels to effectively be used to meet the standards Congress specifically set for cellulosic and advanced biofuels.

If EPA reduces the required volume of cellulosic biofuel, EPA must offer a number of credits no greater than the reduced cellulosic biofuel standard. EISA dictates the cost of these credits and ties them to inflation. The Act also dictates that we must promulgate regulations on the use of these credits and offers guidance on how these credits may be offered and used. We propose that their uses will be very limited. The credits would not be allowed to be traded or banked for future use, but would be allowed to meet the cellulosic biofuel standard, advanced biofuel standard and total renewable fuel standard. Further discussion of the implementation of these provisions can be found in Section III.I.

8. Proposed Standards for 2010

Once the RFS2 program is implemented, we expect to conduct a notice-and-comment rulemaking process each year in order to determine the appropriate standards applicable in the following year. We therefore intend to issue an NPRM in the spring and a final rule by November 30 of each year as required by statute.

However, for the 2010 compliance year, today's action provides a means for seeking comment on the applicable standards. Therefore, rather than issuing a separate NPRM for the 2010 standard, we are proposing the 2010 standards in today's notice. We will consider comments received during the comment period associated with today's NPRM, and we expect to issue a **Federal Register** notice by November 30, 2009 setting the applicable standards for 2010.

We propose that the RFS2 program be effective on January 1, 2010. Therefore, all EISA volume mandates for 2010 would be implemented in that year, unless EPA exercised its authority to waive one or more of the standards. Based on information from the industry, we believe that there are sufficient plans underway to build plants capable of producing 0.1 billion gallons of cellulosic biofuel in 2010, the minimum volume of cellulosic biofuel required by EISA for 2010. However, we recognize that cellulosic biofuel is at the very earliest stages of commercialization and current economic concerns could have significant impacts on these near term plans. Therefore, while based on industry plans available to EPA, we are not proposing that any portion of the cellulosic biofuel requirement for 2010 be waived, we are seeking additional and updated information that would be available prior to November 30, 2009 which could result in a change in this conclusion. Similarly, we are not aware of the need to waive any other volume mandates for 2010. Therefore, we are proposing that the volumes shown in Table II.A.1–1 for all four renewable fuel categories be used as the basis for the applicable standards for 2010. The proposed standards are shown in Table II.A.8–1, each representing the fraction of a refiner's or importer's gasoline and diesel volume which must be renewable fuel.

TABLE II.A.8–1—PROPOSED STANDARDS FOR 2010

[Percent]

Cellulosic biofuel	0.06
Biomass-based diesel	0.71
Advanced biofuel	0.59
Renewable fuel	8.01

Note that the proposed 2010 standards shown in Table II.A.8–1 were based on currently available projections of 2010 gasoline and diesel volumes. The final standards will be calculated on the basis of gasoline and diesel volume projections from the Energy Information Administration's (EIA) Short-Term Energy Outlook and published by November 30, 2009. Additional discussion of our proposed 2010 standards can be found in Section III.E.1.b.

Note also that the proposed standards assume an effective date of January 1, 2010 for RFS2. We are taking comment on alternative effective dates for RFS2, including January 1, 2011 and a date after January 1, 2010 but before January 1, 2011. Such alternative effective dates would raise issues with regard to the calculation and application of the standards for total renewable fuel and the other standards required under EISA, as well as the generation and application of RINs under RFS1 and RFS2. As described more fully in Section III.E.1.d, we request comment on the issues associated with alternative effective dates for RFS2.

B. Impacts of Increasing Volume Requirements in the RFS2 Program

The displacement of gasoline and diesel with renewable fuels has a wide range of environmental and economic impacts. As we describe below, we have assessed many of these impacts for the RFS2 proposal and we will have more complete assessments, including a cost-benefit comparison, for the final rule. These assessments provide important information to the wider public policy considerations of renewable fuels, climate change, and national energy security. They are also an important component of all significant rulemakings.

However, because the volumes of renewable fuel were specified by statute, they would not be based on or revised by our analysis of impacts. In addition, because we have very limited discretion to pursue regulatory alternatives, the proposal does not include a systematic alternatives analysis. We have investigated regulatory alternatives in some areas to the degree that EISA provides discretion.

As one point of reference to assess the impacts of the volume requirements for the RFS2 program, we used projections for renewable fuel use in 2022 that EIA issued through their 2007 Annual Energy Outlook (AEO), and for transportation fuel consumption through their 2008 AEO. This reference case, referred to as the ''AEO Reference Case,'' represents a projection of the demand for renewable fuels prior to enactment of EISA while still reflecting the new Corporate Average Fuel Economy (CAFE) requirements in EISA, and the 2008 AEO projections for the future price of crude oil ($53 to $92 per barrel). Further discussion of the Reference Case can be found in Section V.A.1. Other points of reference include the renewable fuel volumes mandated by EPAct for the RFS1 program, renewable fuel use prior to implementation of the RFS1 program, and the full impacts of renewable fuel use compared to a petroleum-only economy.

Given the short time provided by Congress to conduct a rulemaking, many of our analyses were done in parallel for this proposal. As a result, some analyses were conducted without the benefit of waiting for the conclusion of another analysis that could prove influential. Thus, for example, impacts on food prices assume that soy-based biodiesel and sugarcane ethanol will qualify as advanced fuels under the proposed RFS2 program, even though the analyses conducted for this proposal might preclude such eligibility. We have highlighted such inconsistencies in results and assumptions throughout the proposal. Additionally, since we have identified many issues and analytical options in our assessment of which biofuel pathways would comply with the GHG thresholds, the assessment we conducted for this proposal may not reflect the final rule in all cases. We will be addressing these issues of analytical consistency between analyses more fully in the final rule.

In a similar fashion, while we recognize uncertainty in our assessment of impacts of the proposed RFS2 program, we do not present a formal, comprehensive analysis of uncertainty. For this proposal, many of the analyses are without precedent, and as a result we have identified the more uncertain aspects of these analyses and have worked to assess their potential impact on the results through sensitivity analyses. We intend to continue these assessments for the final rule, and expect that comments on this proposal will allow us to reduce our uncertainty in a number of areas. In addition to this sensitivity analysis approach, we will also explore options for more formal uncertainty analyses for the final rule to the extent possible.

1. Greenhouse Gases and Fossil Fuel Consumption

Our analyses of GHG impacts consider the full useful life assessment of the production of biofuels compared to the petroleum-based fuels they would replace. The analysis compared the AEO reference case transportation fuel pool in 2022 without the EISA mandates with the same fuel pool in 2022, but assuming the greater volumes of biofuel as mandated by EISA replace an energy equivalent amount of petroleum-based fuel. The incremental volumes of each biofuel type were then evaluated to determine their average impact on GHG emissions compared to the 2005 baseline petroleum fuel they would be displacing. These average GHG emission reduction results can then be compared to the threshold performance levels for each fuel type.

As a result of the transition to greater renewable fuel use, some petroleum-based gasoline and diesel will be directly replaced by renewable fuels. Therefore, consumption of petroleum-based fuels will be lower than it would be if no renewable fuels were used in transportation vehicles. However, a true measure of the impact of greater use of renewable fuels on petroleum use, and indeed on the use of all fossil fuels, accounts not only for the direct use and combustion of the finished fuel in a vehicle or engine, but also includes the petroleum use associated with production and transportation of that fuel. For instance, fossil fuels are used in producing and transporting renewable feedstocks such as plants or animal byproducts, in converting the renewable feedstocks into renewable fuel, and in transporting and blending the renewable fuels for consumption as motor vehicle fuel. Likewise, fossil fuels are used in the production and transportation of petroleum and its finished products. In order to estimate the true impacts of increases in renewable fuel use on fossil fuel use, we must take these steps into account. Such analyses are termed lifecycle analyses.

The definition of lifecycle greenhouse gas emissions in EISA requires the Agency to look broadly at lifecycle analyses and to develop a methodology that accounts for the significant secondary or indirect impacts of expanded biofuels use. These indirect effects include both the domestic and international impact of land use change from increased biofuel feedstock production and the secondary agricultural sector GHG impacts from increased biofuel feedstock production (e.g., changes in livestock emissions due to changes in agricultural commodity prices). Today no single model can capture all of the complex interactions required to conduct a complete lifecycle assessment as required by Congress. As a result, the methodology EPA has currently evaluated uses a number of models and tools to provide a comprehensive estimate of GHG emissions. We have used a combination of peer reviewed models including Argonne National Laboratory's GREET model, Texas A&M's Forestry and Agricultural Sector Optimization Model (FASOM) and Iowa State University's Food and Agricultural Policy Research Institute's (FAPRI) international agricultural models as well as the Winrock International database to estimate lifecycle GHG emissions estimates. These models are described in more detail in Section VI and have been used in combination to provide the lifecycle GHG estimates presented in this proposal. However, we recognize other models and sources of information can also be used and these are also discussed in Section VI.

Based on the combined use of these models we have estimated the lifecycle GHG emissions for a number of pathways for producing the increased volumes of renewable fuels as mandated by EISA. Section VI of this proposal outlines the approach taken and describes the key assumptions and parameters used in this analysis. In addition, this section highlights the impacts of varying these key inputs on the overall results.

We estimate the greater volumes of biofuel mandated by RFS2 will reduce lifecycle GHG emissions from transportation by approximately 6.8 billion tons of CO_2 equivalent emissions when accounting for all the emissions changes over 100 years and then discounting this emission stream by 2% per year. This is equivalent to an average annualized emission rate of 160 million metric tons of CO_2-eq. emissions per year over the entire 100 year modeling time frame if that average annualized emission rate is also discounted at 2% per year. Determining lifecycle GHG emissions values for renewable fuels using a 0% discount rate over 30 years would result in an estimated total reduction of 4.5 billion tons of CO_2-eq. over the 30 year period or an average annualized emission rate reduction of 150 million metric tons of CO_2-eq. GHG emissions per year. (See Section VI.F of this preamble for additional information on how these emission reductions were calculated).

Our analysis of the petroleum consumption impacts took a similar lifecycle approach. For the year 2022, we estimate that the 36 billion gallons of renewable fuel mandated by these rules will increase renewable fuel usage by approximately 22 billion gallons which will displace about 15 billion gallons of petroleum-based gasoline and diesel fuel. This represents about 8% of annual oil consumed by the transportation sector in 2022.

2. Economic Impacts and Energy Security

The substantially increased volumes of renewable fuel that would be required under RFS2 would produce a variety of different economic impacts. These would include changes in the cost of gasoline and diesel, a reduction in nationwide expenditures on petroleum imports and the associated increase in energy security, and increases in the prices of agricultural commodities such as corn and soybeans.

The RFS program is projected to significantly impact the cost of gasoline and diesel, though the estimated costs vary based on the price of crude oil that is assumed. In our analysis we used both $92 and $53 per barrel crude oil based on price projections made by EIA. At these two crude oil price points, we estimate that gasoline costs would increase by about 2.7 and 10.9 cents per gallon, respectively, by 2022. Likewise, diesel fuel costs could experience a small cost reduction of 0.1 cents per gallon, or increase by about 1.2 cent per gallon, respectively. For the nation as a whole, these costs are equivalent to $4 and $18 billion in 2022, respectively (in 2006 dollars, and amortizing capital costs using a 7% before-tax rate of return). These costs represent the nationwide average impacts including the costs of producing and distributing both renewable fuels and gasoline and diesel, as well as blending costs, but without consideration of either the tax subsidies and import tariff for ethanol or tax subsidies for biodiesel and renewable diesel fuel.

EPA's estimates of economic impacts of fuels do not consider other societal benefits. For example, the displacement of petroleum-based fuel (largely imported) by renewable fuel (largely produced in the United States), should reduce our consumption of imported oil and fuel. We estimate that 91% of the lifecycle petroleum reductions resulting from the use of renewable fuel will be met through reductions in net petroleum imports. In Section IX of this preamble we estimate the value of the decrease in imported petroleum at about $12.4 billion in 2022 due to increased volumes of renewable fuels mandated by RFS2 in comparison to the AEO reference case. Net U.S. expenditures on petroleum imports in 2022 are projected to be about $208 billion.

Furthermore, the above estimate of reduced U.S. petroleum import expenditures only partly assesses the economic impacts of this proposal. One of the effects of increased use of renewable fuel is that it diversifies the energy sources used in making transportation fuel. To the extent that diverse sources of fuel energy reduce the U.S. dependence on any one source, the risks, both financial as well as strategic, of a potential disruption in supply of a particular energy source are reduced. EPA has worked with researchers at Oak Ridge National Laboratory (ORNL) to update a study they previously published that has been used or cited in several government actions impacting U.S. oil consumption. This updated study went through an independent, third-party peer review process and a final draft report of this updated study was developed. This peer-reviewed report is being made available in the docket at this time for further consideration. Using the updated ORNL estimate, the total energy security benefits associated with a reduction of U.S. imported oil is $12.38 per barrel of imported oil that is reduced. Based on these values, we estimate that the total annual energy security benefits would be $3.7 billion in 2022 (in 2006 dollars).

We recognize that our current energy security analysis does not take into account risk-shifting that might occur as the U.S. reduces its dependency on petroleum by increasing its use of biofuels. For example, our analysis did not take into account other energy security implications associated with biofuels, such as possible supply disruptions of corn-based ethanol. We will attempt to broaden our energy security analysis to incorporate estimates of overall motor fuel supply and demand flexibility and reliability for the final rule, along with impacts of possible agricultural sector market disruptions. A complete discussion of the Agency's plans for this analysis can be found in Section IX.B.2. of this preamble.

While increased use of renewable fuel will reduce expenditures on imported oil, it will also increase expenditures on renewable fuels and in turn on the sources of those renewable fuels. The RFS program is likely to spur the increased use of renewable transportation fuels made principally from agricultural crops and it is expected that most of these crops will be produced in the U.S. As a result, it is important to analyze the consequences of the transition to greater renewable fuel use in the U.S. agricultural sector. To analyze the domestic agricultural sector impacts, EPA selected the Forest and Agricultural Sector Optimization Model (FASOM) developed by Professor Bruce McCarl of Texas A&M University and others over the past thirty years. FASOM is a dynamic, nonlinear programming model of the agriculture and forestry sectors of the U.S.

In Section IX of this preamble, we estimate the change in the price of various agricultural products as a result of this rulemaking. By 2022, we estimate the price of corn would increase by $0.15 per bushel (4.6%) above the Reference Case price of $3.19 per bushel. By 2022, U.S. soybean prices would increase by $0.29 per bushel (2.9%) above the Reference Case price of $9.97 per bushel. Due to higher commodity prices, FASOM estimates that U.S. food costs would increase by $10 per person per year by 2022, relative to the Reference Case. Total farm gate food costs would increase by $3.3 billion (0.2%) in 2022. As a result of increased renewable fuel requirements, FASOM predicts that net U.S. farm income would increase by $7.1 billion dollars in 2022 (10.6%), relative to the Reference Case.

Due to higher commodity prices, FASOM estimates that U.S. corn exports would drop from 2.7 billion bushels under the Reference Case to 2.4 billion bushels (a 10% decrease) by 2022. In value terms, U.S. exports of corn would fall by $487 million in 2022. FASOM estimates that U.S. exports of soybeans would decrease from 1.03 billion bushels to 943 million bushels (an 8% decrease) in 2022. In value terms, U.S. exports of soybeans would decrease by $691 million in 2022.

Assuming current subsidies remain in place, the Renewable Fuels Standard, by encouraging the use of biofuels, will result in an expansion of subsidy payments by the U.S. government. If this resulting loss of tax revenue were offset by an increase in taxes, this could have a distortionary impact on the economy. We intend to consider the impact of the expansion of biofuel subsidies associated with the RFS2 in the context of the economy-wide modeling to be conducted for the final rule.

We note that the economic analyses that support this proposal do not reflect all of the potentially quantifiable economic impacts. There are several key impacts that remain incomplete as a result of time and resource constraints, including the economic impact analysis (see Section IX) and the air quality and health impacts analysis (see Section II.B.3). As a result, this proposal does not combine economic impacts in an attempt to compare costs and benefits, in order to avoid presenting an incomplete and potentially misleading characterization. For the final rule, when the planned analyses are complete and current analyses updated, we will provide a consistent cost-benefit comparison.

3. Emissions, Air Quality, and Health Impacts

Analysis of criteria and toxic emission impacts was performed relative to three different reference case ethanol volumes, ranging from 3.64 to 13.2 billion gallons per year. To assess the total impact of the RFS program, emissions were analyzed relative to the RFS1 rule base case of 3.64 billion gallons in 2004. To assess the impact of today's RFS2 proposal relative to the current mandated volumes, we analyzed impacts relative to RFS1 mandate of 7.5 billion gallons of renewable fuel use by 2012, which was estimated to include 6.7 billion gallons of ethanol.[4] In order to assess the impact of today's proposal relative to the level of ethanol projected to be used in 2022 without RFS2, the AEO2007 projection of 13.2 billion gallons of ethanol in 2022 was analyzed.

We are also presenting a range of impacts meant to bracket the impacts of ethanol blends on light-duty vehicle emissions. Similar to the approach presented in the RFS1 rule, we present a ''less sensitive'' and ''more sensitive'' case to present a range of the possible

[4] RFS1 base and mandated ethanol levels were projected to remain essentially unchanged in 2022 due to the flat energy demands projected by EIA.

emission impacts of E10 on recent model year light duty gasoline vehicles. As detailed in Section VII.C, ''less sensitive'' does not apply any E10 effects to NO_X or HC emissions for later model year vehicles, or E85 effects for any pollutant, while ''more sensitive'' does.

Our projected emission impacts for the ''less sensitive'' and ''more sensitive'' cases are shown in Table II.B.3–1 and II.B.3–2, showing the expected emission changes for the U.S. in 2022, and the percent contribution of this impact relative to the total U.S. inventory across all sectors. Overall we project the proposed program will result in significant increases in ethanol and acetaldehyde emissions—increasing the total U.S inventories of these pollutants by up to 30–40% in 2022 relative to the RFS1 mandate case. We project more modest but still significant increases in acrolein, NO_X, formaldehyde and PM. We project today's action will result in decreased ammonia emissions (due to reductions in livestock agricultural activity), decreased CO emissions (driven primarily by the impacts of ethanol on exhaust emissions from vehicles and nonroad equipment), and decreased benzene emissions (due to displacement of gasoline with ethanol in the fuel pool). Discussion and a breakdown of these results by the fuel production/distribution and vehicle and equipment emissions are presented in Section VII.

TABLE II.B.3–1—RFS2 ''LESS SENSITIVE'' CASE EMISSION IMPACTS IN 2022 RELATIVE TO EACH REFERENCE CASE

Pollutant	RFS1 base		RFS1 mandate		AEO2007	
	Annual short tons	% of total U.S. inventory	Annual short tons	% of total U.S. inventory	Annual short tons	% of total U.S. inventory
NO_X	312,400	2.8	274,982	2.5	195,735	1.7
HC	112,401	1.0	72,362	0.6	−8,193	−0.07
PM_{10}	50,305	1.4	37,147	1.0	9,276	0.3
$PM_{2.5}$	14,321	0.4	11,452	0.3	5,376	0.16
CO	−2,344,646	−4.4	−1,669,872	−3.1	−240,943	−0.4
Benzene	−2,791	−1.7	−2,507	−1.5	−1,894	−1.1
Ethanol	210,680	36.5	169,929	29.4	83,761	14.5
1,3-Butadiene	344	2.9	255	2.1	65	0.5
Acetaldehyde	12,516	33.7	10,369	27.9	5,822	15.7
Formaldehyde	1,647	2.3	1,348	1.9	714	1.0
Naphthalene	5	0.03	3	0.02	−1	−0.01
Acrolein	290	5.0	252	4.4	174	3.0
SO_2	28,770	0.3	4,461	0.05	−47,030	−0.5
NH_3	−27,161	−0.6	−27,161	−0.6	−27,161	−0.6

TABLE II.B.3–2—RFS2 ''MORE SENSITIVE'' CASE EMISSION IMPACTS IN 2022 RELATIVE TO EACH REFERENCE CASE

Pollutant	RFS1 base		RFS1 mandate		AEO2007	
	Annual short tons	% of total U.S. inventory	Annual short tons	% of total U.S. inventory	Annual short tons	% of total U.S. inventory
NO_X	402,795	3.6	341,028	3.0	210,217	1.9
HC	100,313	0.9	63,530	0.6	−15,948	−0.14
PM_{10}	46,193	1.3	33,035	0.9	5,164	0.15
$PM_{2.5}$	10,535	0.3	7,666	0.2	1,589	0.05
CO	−3,779,572	−7.0	−3,104,798	−5.8	−1,675,869	−3.1
Benzene	−5,962	−3.5	−5,494	−3.3	−4,489	−2.7
Ethanol	228,563	39.6	187,926	32.5	105,264	18.2
1,3-Butadiene	−212	−1.8	−282	−2.4	−430	−3.6
Acetaldehyde	16,375	44.0	14,278	38.4	9,839	26.5
Formaldehyde	3,373	4.7	3,124	4.3	2,596	3.6
Naphthalene	−175	−1.2	−178	−1.3	−187	−1.3
Acrolein	253	4.4	218	3.8	143	2.5
SO_2	28,770	0.3	4,461	0.05	−47,030	−0.5
NH_3	−27,161	−0.6	−27,161	−0.6	−27,161	−0.6

We note that the aggregate nationwide emission inventory impacts presented here will likely lead to health impacts throughout the U.S. due to changes in future-year ambient air quality. However, emissions changes alone are not a good indication of local or regional air quality and health impacts, as there may be highly localized impacts such as increased emissions from ethanol plants and evaporative emissions from cars, and decreased emissions from gasoline refineries. In addition, the atmospheric chemistry related to ambient concentrations of $PM_{2.5}$, ozone and air toxics is very complex, and making predictions based solely on emissions changes is extremely difficult. Full-scale photochemical modeling is necessary to provide the needed spatial and temporal detail to more completely and accurately estimate the changes in ambient levels of these pollutants. As discussed in Section VII.D, timing and resource constraints precluded EPA from conducting a full-scale photochemical air quality modeling analysis in time for the NPRM. For the final rule, however, a national-scale air quality modeling analysis will be performed to analyze the impacts of the proposed standards on $PM_{2.5}$, ozone, and selected air toxics (i.e., benzene, formaldehyde, acetaldehyde, ethanol, acrolein and 1,3-butadiene). As described in Section VII.D.2, EPA intends to use a 2005-based Community Multi-scale Air Quality (CMAQ) modeling platform as the tool for the air quality modeling. The CMAQ modeling system is a comprehensive three-dimensional grid-based Eulerian air quality model designed to estimate the formation and fate of oxidant precursors, primary and secondary PM concentrations and deposition, and air toxics, over regional and urban spatial scales (e.g., over the contiguous U.S.).

The lack of air quality modeling data also precluded EPA from conducting its standard analysis of human health impacts, where CMAQ output data are used as inputs to the Environmental Benefits Mapping and Analysis Program (BenMAP). Section IX.D of this preamble describes the human health impacts that will be quantified and monetized for the final rule, as well as the unquantified impacts that will be qualitatively described.

4. Water

As the production of biofuels increases to meet the requirements of this proposed rule, there may be adverse impacts on both water quality and quantity. Increased production of biofuels may lead to increased application of fertilizer and pesticides and increased soil erosion, which could impact water quality. Since ethanol production uses large quantities of water, the supply of water could also be significantly impacted in some locations.

EPA focused the water quality analysis for this proposal on the impacts of corn produced for ethanol for several reasons. Corn has the highest fertilizer and pesticide use per acre and accounts for the largest share of nitrogen fertilizer use among all crops. Furthermore, corn-based ethanol is expected to be a large component of the biofuels mix.

Fertilizer nutrients that are not used by the crops are available to runoff to surface water or leach into groundwater. Nutrient enrichment due to human activities is one of the leading problems facing our nation's lakes, reservoirs, and estuaries, and also has negative impacts on aquatic life in streams; adverse health effects on humans and domestic animals; and impairs aesthetic and recreational use. Excess nutrients can lead to excessive growth of algae in rivers and streams, and aquatic plants in all waters. Nutrient pollution is widespread. The most widely known examples of significant nutrient impacts include the Gulf of Mexico and the Chesapeake Bay, however waterbodies in virtually every state and territory are impacted by nutrient-related degradation. A more detailed discussion of nutrient pollution can be found in Section X of this preamble and in Chapter 6 of the DRIA.

To provide a quantitative estimate of the impact of this proposal and production of corn ethanol generally on water quality, EPA conducted an analysis that modeled the changes in loadings of nitrogen, phosphorus, and sediment from agricultural production in the Upper Mississippi River Basin (UMRB). The UMRB is representative of the many potential issues associated with ethanol production, including its connection to major water quality concerns such as Gulf of Mexico hypoxia, large corn acreage, and numerous ethanol production plants. The UMRB contributes 39% of nitrogen loads and 26% of phosphorus loads to the Gulf of Mexico.

EPA selected the SWAT (Soil and Water Assessment Tool) model to assess nutrient loads from changes in agricultural production in the UMRB. SWAT is a physical process model developed to quantify the impact of land management practices in large, complex watersheds. In conducting its analysis EPA quantified the impacts from a baseline that preceded the current high production of ethanol from corn to four future years—2010, 2015, 2020 and 2022.

Table II.B.4–1 summarizes the model outputs at the outlet of the UMRB in the Mississippi River at Grafton, Illinois for each of the four scenario years. The local impact in smaller watersheds within the UMRB may be significantly different. The decreasing nitrogen load over time is likely attributed to the increased corn yield production, resulting in greater plant uptake of nitrogen. The relatively stable sediment loadings are likely due to the fact that corn was modeled assuming that corn stover is left on the fields following harvest.

TABLE II.B.4–1—CHANGES FROM THE 2005 BASELINE TO THE MISSISSIPPI RIVER AT GRAFTON, ILLINOIS FROM THE UPPER MISSISSIPPI RIVER BASIN

	2005 Baseline	2010	2015	2020	2022
Average corn yield (bushels/acre)	141	150	158	168	171
Nitrogen	1433.5 million lbs	+5.5%	+4.7%	+2.5%	+1.8%
Phosphorus	132.4 million lbs	+2.8%	+1.7%	+0.98%	+0.8%
Sediment	6.4 million tons	+0.5%	+0.3%	+0.2%	+0.1%

After evaluating comments on this proposal, if time and resources permit, EPA may conduct additional water quality analyses using the SWAT model in the UMRB. Potential future analyses could include: (1) Determination of the most sensitive assumptions in the model, (2) water quality impacts from the changes in ethanol volumes between the reference case and this proposal, (3) removing corn stover for cellulosic ethanol, and (4) a case study of a smaller watershed to evaluate local water quality impacts that are impossible to ascertain at the scale of the UMRB.

EPA also qualitatively examined other water issues, which are also discussed in detail in Section X of this Preamble, and Chapter 6 of the DRIA.

5. Agricultural Commodity Prices

The recent increase in food prices, both domestically and internationally, has raised the issue of whether diverting grains and oilseeds for fuel production is having a large impact on commodity markets. While we share the concern that food prices have increased significantly over the same time period in which renewable fuel production has increased, many factors have contributed to recent increases in food prices. As described by the U.S. Department of Agriculture (USDA), the Department of Energy (DOE), the Council of Economic Advisors (CEA), and others, the recent increase in commodity prices has been influenced by factors as diverse as world economic growth, droughts in Australia, China and Eastern Europe, increasing oil prices, changes in investment strategies, and the declining value of the U.S. dollar. While the increase in renewable fuel production has contributed to the increase in commodity prices, the magnitude of the contribution of the RFS has most likely been minor, as market conditions have continued to push renewable fuel use beyond the mandated levels.

As the mandated levels of renewable fuels continue to rise in the future, our economic modeling suggests that the impact of the RFS2 program on food prices will continue to be modest, particularly with the expansion of cellulosic biofuels. Table II.B.5–1 summarizes the changes in prices for some commodities we have estimated for this proposal. Further discussion can be found in Section IX.A.

TABLE II.B.5–1—CHANGE IN U.S. COMMODITY PRICES FOR 2022 IN COMPARISON TO THE REFERENCE CASE

[2006$]

Corn	$0.15/bushel.
Soybeans	$0.29/bushel.
Sugarcane	$13.34/ton.
Beef	$0.93/hundred pounds.

II. What Are the Major Elements of the Program Required Under EISA?

While EISA made a number of changes to CAA section 211(o) that must be reflected in the RFS program regulations, it left many of the basic program elements intact, including the mechanism for translating national renewable fuel volume requirements into applicable standards for individual obligated parties, requirements for a credit trading program, geographic applicability, treatment of small refineries, and general waiver provisions. As a result, we propose that many of the regulatory requirements of the RFS1 program would remain largely or, in some cases, entirely unchanged. These provisions would include the distribution of RINs, separation of RINs, use of RINs to demonstrate compliance, provisions for exporters, recordkeeping and reporting, deficit carryovers, and the valid life of RINs.

The primary elements of the RFS program that we propose changing to implement the requirements in EISA fall primarily into the following five areas:

(1) Expansion of the applicable volumes of renewable fuel

(2) Separation of the volume requirements into four separate categories of renewable fuel, with corresponding changes to the RIN and to the applicable standards

(3) Changes to the definition of renewable fuels and criteria for determining which if any of the four renewable fuel categories a given renewable fuel is eligible to meet

(4) Expansion of the fuels subject to the standards (and applicable to refiners, blenders, and importers of those fuels) to include diesel and certain nonroad fuels

(5) Inclusion of specific types of waivers and EPA-generated credits for cellulosic biofuel.

EISA does not change the basic requirement under CAA 211(o) that the RFS program include a credit trading program. In the May 1, 2007 final rulemaking implementing the RFS1 program, we described how we reviewed a variety of approaches to program design in collaboration with various stakeholders. We finally settled on a RIN-based system for compliance and credit purposes as the one which met our goals of being straightforward, maximizing flexibility, ensuring that volumes are verifiable, and maintaining the existing system of fuel distribution and blending. RINs represent the basic framework for ensuring that the statutorily required volumes of renewable fuel are produced and used as transportation fuel in the U.S. The use of RINs is predicated on the fact that once renewable fuels are produced or imported, there is very high confidence that, setting aside exports, all but de minimus quantities will in fact be used as transportation fuel in the U.S. Focusing on production of renewable fuel as a surrogate for the later actual blending and use of such fuel has many benefits as far as streamlining the RFS program and minimizing the impact that the program has on the business operations of the regulated industries. Since the RIN-based system generally has been successful in meeting EPA's goals, we propose to maintain much of its structure under RFS2.

This section describes the regulatory changes we propose to implement the new EISA provisions. Section IV describes other changes to the RFS program that we have considered or are proposing, including a concept for an EPA-moderated RIN trading system that would provide a context within which all RIN transfers could occur.

A. Changes to Renewable Identification Numbers (RINs)

Under RFS2, we propose that each RIN would continue to represent one gallon of renewable fuel for compliance purposes consistent with our approach under RFS1, and the RIN would continue to have 38 digits. In general the codes within the RIN would have the same meaning under RFS2 as they do under RFS1, with the exception of the D code which would be expanded to cover the four categories of renewable fuel defined in EISA. The proposed change to the D code is described in Table III.A–1.

TABLE III.A–1—PROPOSED CHANGE TO D CODE

D value	Meaning under RFS1	Meaning under RFS2
1	Cellulosic biomass ethanol	Cellulosic biofuel.
2	Any renewable fuel that is not cellulosic biomass ethanol	Biomass-based diesel.
3	Not applicable	Advanced biofuel.
4	Not applicable	Renewable fuel.

The determination of which D code would be assigned to a given batch of renewable fuel is described in more detail in Section III.D.2 below.

As described in Section II.A.5, we are proposing that the RFS2 program go into effect on January 1, 2010. However, we are also taking comment on other potential start dates including January 1, 2011 and dates between January 1, 2010 and January 1, 2011. If we were to start the RFS2 program during 2010 but after January 1, some 2010 RINs would be generated under the RFS1 requirements and others would be generated under the RFS2 requirements, but all RINs generated in 2010 would need to be valid for meeting the appropriate 2010 annual standards. Since RFS1 RINs and RFS2 RINs would differ in the meaning of the D codes, we would need a mechanism for distinguishing between these two categories of RINs in order to appropriately apply them to the standards. One straightforward way of accomplishing this would be to use values for the D code under RFS2 that do not overlap the values for the D code under RFS1. Table III.A–2 describes the D code definitions under such an alternative approach.

TABLE III.A–2—ALTERNATIVE D CODE DEFINITIONS

D value	Meaning under RFS1	Meaning under RFS2
1	Cellulosic biomass ethanol	Not applicable.
2	Any renewable fuel that is not cellulosic biomass ethanol	Not applicable.
3	Not applicable	Cellulosic biofuel.
4	Not applicable	Biomass-based diesel.
5	Not applicable	Advanced biofuel.
6	Not applicable	Renewable fuel.

In this alternative approach, D code values of 1 and 2 would only be relevant for RINs generated under RFS1, and D code values of 3, 4, 5, and 6 would only be relevant for RINs generated under RFS2. As a result, 2010 RINs generated under RFS1 would be subject to our proposed RFS1/RFS2 transition provisions wherein they would be assigned to one of the four annual standards that would apply in 2010 using their RR and/or D codes. See Section III.G.3 for further description of how we propose using RFS1 RINs to meet standards under RFS2.

Under RFS2, each batch-RIN generated would continue to uniquely identify not only a specific batch of renewable fuel, but also every gallon-RIN assigned to that batch. Thus the RIN would continue to be defined as follows:

RIN: KYYYYCCCCFFFFFBBBBBR RDSSSSSSSSEEEEEEEE

Where:

K = Code distinguishing assigned RINs from separated RINs
YYYY = Calendar year of production or import
CCCC = Company ID
FFFFF = Facility ID
BBBBB = Batch number
RR = Code identifying the Equivalence Value
D = Code identifying the renewable fuel category
SSSSSSSS = Start of RIN block
EEEEEEEE = End of RIN block

B. New Eligibility Requirements for Renewable Fuels

Aside from the higher volume requirements, most of the substantive changes that EISA makes to the RFS program affect the eligibility of renewable fuels in meeting one of the four volume requirements. Eligibility would be determined based on the types of feedstocks that can be used, the land that can be used to grow feedstocks for renewable fuel production, the processes that can be used to convert those feedstocks into fuel, and the lifecycle greenhouse gas (GHG) emissions that can be emitted in comparison to the gasoline or diesel that the renewable fuel displaces. This section describes these eligibility criteria and how we propose to include them in the RFS2 program.

1. Changes in Renewable Fuel Definitions

Under the existing Renewable Fuel Standard (RFS1), renewable fuel is defined generally as ‘‘any motor vehicle fuel that is used to replace or reduce the quantity of fossil fuel present in a fuel mixture used to fuel a motor vehicle’’. The RFS1 definition includes motor vehicle fuels produced from biomass material such as grain, starch, fats, greases, oils, and biogas. The definition specifically includes cellulosic biomass ethanol, waste derived ethanol, and biodiesel, all of which are defined separately. (*See* 72 FR 23915.)

The definitions of renewable fuels under today's proposed rule (RFS2) are based on the new statutory definition in EISA. Like the existing rules, the definitions in RFS2 include a general definition of renewable fuel, but unlike RFS1, we are including a separate definition of ‘‘Renewable Biomass’’ which identifies the feedstocks from which renewable fuels may be made.

Another difference in the definitions of renewable fuel is that RFS2 contains three subcategories of renewable fuels: (1) Advanced Biofuel, (2) Cellulosic Biofuel and (3) Biomass-Based Diesel. Each must meet threshold levels of reduction of greenhouse gas emissions as discussed in Section III.B.2. The specific definitions and how they differ from RFS1 follow below.

a. Renewable Fuel and Renewable Biomass

‘‘Renewable Fuel’’ is defined as fuel produced from renewable biomass and that is used to replace or reduce the quantity of fossil fuel present in a transportation fuel. The definition of ‘‘Renewable Fuel’’ now refers to ‘‘transportation fuel’’ rather than referring to motor vehicle fuel. ‘‘Transportation fuel’’ is also defined, and means fuel used in motor vehicles, motor vehicle engines, nonroad vehicles or nonroad engines (except for ocean going vessels).

We propose to allow fuel producers and importers to include electricity, natural gas, and propane (i.e., compressed natural gas (CNG) and liquefied petroleum gas (LPG)) as a RIN-generating renewable fuel in today's program only if they can identify the specific quantities of their product which are actually used as a transportation fuel, and if the fuel is produced from renewable biomass. This may be possible for some portion of electricity, natural gas, and propane since many of the affected vehicles and equipment are in centrally-fueled fleets supplied under contract by a particular producer or importer of natural gas or propane. A producer or importer of electricity, natural gas, or propane who could document the use of his product in a vehicle or engine would be allowed to generate RINs to represent that product, if it met the definition of renewable fuel. Given that the primary use of electricity, natural gas, and propane is not for fueling vehicles and engines, and the producer generally does not know how it will be used, we cannot require that producers or importers of these fuels generate RINs for all the volumes they produce as we do with other renewable fuels.

Our proposal to allow electricity, natural gas, and propane to generate RINs under certain conditions is consistent with our treatment of neat renewable fuels under RFS1 and EISA's requirement that all transportation fuels be included in RFS2. With specific regard to renewable electricity, Section 206 of EISA requires the EPA to conduct a study of the feasibility of issuing credits under the RFS2 program for renewable electricity used by electric vehicles. Once completed, this study will provide additional information regarding the means by which renewable electricity is able to generate RINs under the RFS2 program.

As an alternative to allowing producers and importers of electricity, natural gas, and propane to generate RINs if they can demonstrate that their product is a renewable fuel and it is used as transportation fuel, we could allow or require parties who supply these fuels to centrally fueled fleets to generate the RINs even if they are not the producer of the fuel. This approach would treat the supplier of the fuel to the fleet as the producer or importer who then generates RINs, as they are the party who in effect changes the fuel from a fuel that can be used in a variety of ways and ensures that it is in fact used as transportation fuel. This alternative approach might enable a larger volume of electricity, natural gas, and propane that is made from renewable biomass and which is actually used in vehicles or engines to be included in our proposed fuels program as RIN-generating, since in many cases a supplier could document the use of these fuels in vehicles or engines, while a producer could not. In addition, in this case the supplier is the party who causes the fuel to transition from general fuel supply to fuel designated for use in motor vehicles or nonroad applications—in that sense, the supplier is more like a producer or importer than the upstream producer or importer. However, if we were to allow the supplier of renewable electricity, natural gas, or propane to generate RINs in such cases, it may also be appropriate to require suppliers of fossil-based electricity, natural gas, or propane to determine a Renewable Volume Obligation (RVO) that includes these fuels used as transportation fuel. See Section III.F.3 for further discussion. We request comment on this alternative approach for generating RINs for renewable electricity, natural gas and propane.

The term ''Renewable Biomass'' as defined in EISA, means:

1. Planted crops and crop residue,
2. Planted trees and tree residues,
3. Animal waste material and byproducts,
4. Slash and pre-commercial thinnings (from non-federal forestlands),
5. Biomass cleared from the vicinity of buildings and other areas to reduce the risk of wildfire,
6. Algae, and
7. Separated yard waste or food waste.

Section III.B.4 of this preamble outlines our proposed interpretations for most of the key terms contained in the EISA definition of ''renewable biomass'' and possible approaches for implementing the land restrictions on renewable biomass that are included in EISA. It is worth noting here, however, that the statutory definition of ''renewable biomass'' does not include a reference to municipal solid waste (MSW) as did the definition of ''cellulosic biomass ethanol'' in the Energy Policy Act of 2005 (EPAct), but instead includes ''separated yard waste and food waste. EPA's proposed definition of renewable biomass in today's regulation includes the language present in EISA, and we propose to clarify in the regulations that ''yard waste'' is leaves, sticks, pine needles, grass and hedge clippings, and similar waste from residential, commercial, or industrial areas. Nevertheless, EPA invites comment on whether the definition of ''renewable biomass'' should be interpreted as including or excluding MSW from the definition of renewable biomass.

While the lack of a reference to MSW and the new listing of separated yard waste and food waste could be readily interpreted to exclude MSW as a qualifying feedstock under RFS2, EPA believes there are indications of ambiguity on this issue and solicits comment on whether EPA can and should interpret EISA as including MSW that contains yard and/or food waste within the definition of renewable biomass. On the one hand, the reference in the statutory definition to ''separated yard waste and food waste,'' and the lack of reference to other components of MSW (such as waste paper and wood waste) suggests that only yard and food wastes physically separated from other waste materials satisfy the definition of renewable biomass as opposed to the yard and food waste present in MSW. This view would exclude unprocessed MSW from any role in the development of renewable fuel under EISA, and would also likely severely limit the amount of yard and food waste available as feedstock for EISA-qualifying fuel, since large quantities of these materials are disposed of as unprocessed MSW.

On the other hand, there are some indications that Congress may not have specifically intended to exclude MSW from playing a role in the development of renewable fuels under EISA. For example, ethanol ''derived from waste material'' and biogas ''including landfill gas'' are specifically identified as ''eligible for consideration'' in the definition of advanced biofuel. While landfill gas is generated primarily by the yard waste and food waste in a landfill, these wastes typically are not separated from each other in a landfill. In addition, Congress did not define the term ''separated'' and did not otherwise specify the degree of ''separation'' required of yard and food waste in the definition of renewable biomass. Thus, it might be reasonable to consider these items sufficiently ''separated'' from other materials, including non-waste materials, when food and yard waste is present in MSW. In addition, the processing of MSW to fuel will effectively separate out the materials in MSW that cannot be made into fuel, such as glass and metal, and non-biomass portions of MSW (for example, pastics) could be excluded from getting credit under the RFS program as described in Section III.D.4. EPA invites comment on whether there is enough separation of food and yard waste in MSW used in renewable fuel production for MSW containing yard and food waste to meet the definition of renewable biomass.

Approximately 35% by weight of MSW is paper wastes, and another 6% by weight from wood wastes. Combined with food and yard wastes, more than 60% by weight of MSW is biomass that could be used to make ethanol and other renewable fuels.[5] The volume of ethanol associated with MSW as a feedstock is described in more detail in Section 1.1 of the Draft Regulatory Impact Analysis (DRIA).

Our discussions with stakeholders indicate that a potential concern with interpreting the definition of renewable biomass to include MSW containing yard and/or food waste is that this approach may cause some decrease in the amount of paper that is separated from the MSW waste stream and recycled into paper products. We believe, however, that current waste handling practices and current and anticipated market conditions would continue to provide a strong incentive for paper separation and recycling. A narrow reading of the statute to exclude MSW-derived renewable fuel would directionally reduce the options available for meeting the goal of EISA to reduce our dependence on foreign sources of energy.

By including MSW containing yard and/or food waste in the definition of renewable biomass, we could also allow renewable fuel to be produced in part from certain plastics in the MSW waste stream. We believe this could be appropriate given that plastics that would otherwise be destined for landfills can be used for fuel and energy production. We recognize that the definition of renewable biomass generally includes only materials of a non fossil-fuel origin, and ask that commenters consider this issue in their comments on whether: (1) MSW containing yard and food waste should qualify as renewable biomass, (2) if non-fossil portions of MSW should be included in the definition of renewable biomass, and (3) if non-fossil portions of

[5] Construction and demolition (C&D) wastes are not typically considered as elements of MSW. Because they are significant feedstocks for the production of ethanol, we include such wastes in our economic analysis (Section V). Therefore, for all practical purposes, the discussion here as it pertains to whether MSW should be included in the definition of ''renewable biomass'' also applies to C&D wastes.

MSW should not be included, whether the approach discussed in Section III.D.4 can provide an appropriate means for excluding the non-fossil portions.

Although we are proposing to exclude MSW from the definition of ''renewable biomass'' for the proposed rule, our analysis of renewable fuel volume (discussed in Section V) assumes that MSW is included for purposes of quantifying the potential future volume of renewable fuel. EPA intends to resolve this matter in the final rule, and we solicit comment on the approach that we should take.

b. Advanced Biofuel

''Advanced Biofuel'' is a renewable fuel other than ethanol derived from corn starch and which must also achieve a lifecycle GHG emission displacement of 50%, compared to the gasoline or diesel fuel it displaces. As such, advanced biofuel would be assigned a D code of 3 as shown in Table III.A–1.

''Advanced biofuel'' also may be biomass-based diesel, biogas (including landfill gas and sewage waste treatment gas), butanol or other alcohols produced through conversion of organic matter from renewable biomass, and other fuels derived from cellulosic biomass, as long as it meets the proposed 40–44% GHG emission reduction threshold. ''Advanced Biofuel'' is a renewable fuel other than ethanol derived from corn starch and for which lifecycle GHG emissions are at least 40–44% less than the gasoline or diesel fuel it displaces. Advanced biofuel would be assigned a D code of 3 as shown in Table III.A–1.

While ''Advanced Biofuel'' specifically excludes ethanol derived from corn starch, it includes other types of ethanol derived from renewable biomass, including ethanol made from cellulose, hemicellulose, lignin, sugar or any starch other than corn starch, as long as it meets the proposed 40–44% GHG emission reduction threshold. Thus, even if corn starch-derived ethanol were made so that it met the proposed 40–44% GHG reduction threshold, it would still be excluded from being defined as an advanced biofuel. Such ethanol, while not an advanced biofuel, would still qualify as a renewable fuel for purposes of meeting the standards.

''Advanced biofuel'' also may be biomass-based diesel, biogas (including landfill gas and sewage waste treatment gas), butanol or other alcohols produced through conversion of organic matter from renewable biomass, and other fuels derived from cellulosic biomass, as long as it is derived from renewable biomass and meets the proposed 40–44% GHG emission reduction threshold.

c. Cellulosic Biofuel

Cellulosic biofuel is renewable fuel, not necessarily ethanol, derived from any cellulose, hemicellulose, or lignin each of which must originate from renewable biomass. It must also achieve a lifecycle GHG emission reduction of at least 60%, compared to the gasoline or diesel fuel it displaces. Cellulosic biofuel is assigned a D code of 1 as shown in Table III.A–1. Cellulosic biofuel in general also qualifies as both ''advanced biofuel'' and ''renewable fuel''.

The proposed definition of cellulosic biofuel for RFS2 is broader in some respects than the RFS1 definition of ''cellulosic biomass ethanol''. That definition included only ethanol, whereas the RFS2 definition of cellulosic biofuels includes any biomass-to-liquid fuel in addition to ethanol. The definition of ''cellulosic biofuel'' in RFS2 differs from RFS1 in another significant way. The RFS1 definition provided that ethanol made at any facility—regardless of whether cellulosic feedstock is used or not—may be defined as cellulosic if at such facility ''animal wastes or other waste materials are digested or otherwise used to displace 90% or more of the fossil fuel normally used in the production of ethanol.'' This provision was not included in EISA, and therefore does not appear in the definitions pertaining to cellulosic biofuel in today's proposed rule.

d. Biomass-Based Diesel

Under today's proposed rule ''Biomass-based diesel'' includes both biodiesel (mono-alkyl esters) and non-ester renewable diesel (including cellulosic diesel). The definition is the same very broad definition of ''biodiesel'' that was in EPAct and in RFS1, with three exceptions. First, EISA requires that such fuel be made from renewable biomass. Second, its lifecycle GHG emissions must be at least 50% less than the gasoline or diesel fuel it displaces. Third, the statutory definition of ''Biomass-based diesel'' excludes renewable fuel derived from co-processing biomass with a petroleum feedstock. In drafting the proposed definition, we considered two options for how co-processing could be treated. The first option would consider co-processing to occur only if both petroleum and biomass feedstock are processed in the same unit simultaneously. The second option would consider co-processing to occur if renewable biomass and petroleum feedstock are processed in the same unit at any time; i.e., either simultaneously or sequentially. Under the second option, if petroleum feedstock was processed in the unit, then no fuel produced from such unit, even from a biomass feedstock, would be deemed to be biomass-based diesel.

We are proposing the first option to be used in the definition in today's rule. Under this approach, a batch of fuel qualifying for the D code of 2 that is produced in a processing unit in which only renewable biomass is the feedstock for such batch, would meet the definition of ''Biomass-Based Diesel. Thus, serial batch processing in which 100% vegetable oil is processed one day/week/month and 100% petroleum the next day/week/month could occur without the activity being considered ''co-processing.'' The resulting products could be blended together, but only the volume produced from vegetable oil would count as biomass-based diesel. We believe this is the most straightforward approach and an appropriate one, given that it would allow RINs to be generated for volumes of fuel meeting the 50% GHG reduction threshold that is derived from renewable biomass, while not providing any credit for fuel derived from petroleum sources. In addition, this approach avoids the need for potentially complex provisions addressing how fuel should be treated when existing or even mothballed petroleum hydrotreating equipment is retrofitted and placed into new service for renewable fuel production or vice versa.

Under today's proposal, any fuel that does not satisfy the definition of biomass-based diesel only because it is co-processed with petroleum would still meet the definition of ''Advanced Biofuel'' provided it meets the 50% GHG threshold and other criteria for the D code of 3. Similarly it would meet the definition of renewable fuel if it meets a GHG emission reduction threshold of 20%. In neither case, however, would it meet the definition of biomass-based diesel.

This restriction is only really an issue for renewable diesel and biodiesel produced via the fatty acid methyl ester (FAME) process. For other forms of biodiesel, it is never made through any sort of co-processing with petroleum.[6]

[6] The production of biodiesel (mono alkyl esters) does require the addition of methanol which is usually derived from natural gas, but which contributes a very small amount to the resulting product. We do not believe that this was intended by the statute's reference to ''co-processing'' which we believe was intended to address only renewable fats or oils co-processed with petroleum in a hydrotreater to produce renewable diesel.

Producers of renewable diesel must therefore specify whether or not they use ''co-processing'' to produce the fuel in order to determine the correct D code for the RIN.

e. Additional Renewable Fuel

The statutory definition of ''additional renewable fuel'' specifies fuel produced from renewable biomass that is used to replace or reduce fossil fuels used in home heating oil or jet fuel. EISA indicates that EPA may allow for the generation of credits for such additional renewable fuel that will be valid for compliance purposes. Under the RFS program, RINs operate in the role of credits, and RINs are generated when renewable fuel is produced rather than when it is blended. In most cases, however, renewable fuel producers do not know at the time of fuel production (and RIN generation) how their fuel will ultimately be used.

Under RFS1, only RINs assigned to renewable fuel that was blended into motor vehicle fuel are valid for compliance purposes. As a result, we created special provisions requiring that RINs be retired if they were assigned to renewable fuel that was ultimately blended into nonroad fuel. The new EISA provisions regarding additional renewable fuel make the RFS1 requirement for retiring RINs unnecessary if renewable fuel is blended into heating oil or jet fuel. As a result, we propose modifying the regulatory requirements to allow RINs assigned to renewable fuel blended into heating oil or jet fuel to continue to be valid for compliance purposes.

2. Lifecycle GHG Thresholds

As part of the new definitions that EISA creates for cellulosic biofuel, biomass-based diesel, advanced biofuel, and renewable fuel, EISA also sets minimum performance measures or ''thresholds'' for lifecycle GHG emissions. These thresholds represent the percent reduction in lifecycle GHGs that is estimated to occur when a renewable fuel displaces gasoline or diesel fuel. Table III.B.2–1 lists the thresholds required by EISA.

TABLE III.B.2–1—REQUIRED LIFECYCLE GHG THRESHOLDS

[Percent reduction from a 2005 gasoline or diesel baseline]

Renewable fuel	20
Advanced biofuel	50
Biomass-based diesel	50
Cellulosic biofuel	60

There are also special provisions for each of these thresholds:

Renewable fuel: The 20% threshold only applies to renewable fuel from new facilities that commenced construction after December 19, 2007, with an additional exemption from the 20% threshold for ethanol plants that commenced construction in 2008 or 2009 and are fired with natural gas, biomass, or any combination thereof. Facilities not subject to the 20% threshold would be ''grandfathered.'' *See* Section III.B.3 below for a complete discussion of grandfathering. Also, EPA can adjust the 20% threshold to as low as 10%, but the adjustment must be the minimum possible, and the resulting threshold must be established at the maximum achievable level based on natural gas fired corn-based ethanol plants.

Advanced biofuel and biomass-based diesel: The 50% threshold can be adjusted to as low as 40%, but the adjustment must be the minimum possible and result in the maximum achievable threshold taking cost into consideration. Also, such adjustments could be made only if it was determined that the 50% threshold was not commercially feasible for fuels made using a variety of feedstocks, technologies, and processes. As described more fully in Section VI.D, we are proposing that the GHG threshold for advanced biofuels be adjusted to 44% or potentially as low as 40% depending on the results from the analyses that will be conducted for the final rule.

Cellulosic biofuel: Similarly to advanced biofuel and biomass-based diesel, the 60% threshold applicable to cellulosic biofuel can be adjusted to as low as 50%, but the adjustment must be the minimum possible and result in the maximum achievable threshold taking cost into consideration. Also, such adjustments could be made only if it was determined that the 60% threshold was not commercially feasible for fuels made using a variety of feedstocks, technologies, and processes.

Our analyses of lifecycle GHG emissions, discussed in detail in Section VI, included all GHGs related to the full fuel cycle, including all stages of fuel and feedstock production and distribution, from feedstock generation and extraction through distribution, delivery, and use of the finished fuel. They included direct emissions and any significant indirect emissions such as significant emissions from land use changes. These lifecycle analyses were used to determine whether the thresholds shown in Table III.B.2–1 should be adjusted downwards and which specific combinations of feedstock, fuel type, and production process met those thresholds under the assumption of a 100-year timeframe and 2% discount rate for GHG emission impacts.

We are not proposing to adjust any of these thresholds. However, we may adjust the GHG threshold for biomass-based diesel and/or advanced biofuel downward for the final rule based on additional lifecycle GHG analyses and further assessments of the market potential for volumes that can meet the requirements for these categories of renewable fuel. As explained in more detail in Section VI.D, ethanol produced from sugarcane sugar has been estimated to have a lifecycle GHG performance of 44% (under the assumption of a 100 year timeframe and 2% discount rate), short of the 50% threshold specified in EISA. Ethanol from sugarcane is one of the few currently commercial pathways that have the potential to meet the requirements for advanced biofuel in the near term (in addition to cellulosic biofuel and biomass-based diesel which are a subset of advanced biofuel, and any other new fuels that may arise), and the only such pathway that was subjected to lifecycle analysis to date. If ethanol from sugarcane does not qualify as advanced biofuel, it is likely that it would not be commercially feasible for the advanced biofuel volume requirements to be met in the near term. We request comment on whether it would be necessary to adjust the GHG threshold for advanced biofuel. For similar reasons, as discussed in more detail in Section VI.D, we are also seeking comment on the need to adjust the GHG threshold for biomass-based diesel.

3. Renewable Fuel Exempt From 20 Percent GHG Threshold

EISA amends section 211(o) of the Clean Air Act to provide that renewable fuel produced from new facilities which commenced construction after December 19, 2007 must achieve at least a 20% reduction in lifecycle greenhouse gas emissions compared to baseline lifecycle greenhouse gas emissions.[7] Facilities that commenced construction before December 19, 2007 are ''grandfathered'' and thereby exempt from the 20% GHG reduction requirement.

[7] Section 211(o)(2)(A)(i) of the Clean Air Act as amended by EISA. Note that this is not a prohibition—facilities that make ethanol can continue to do so. It is a minimum requirement for facilities to generate RINs under today's proposed rule; failure to meet such requirements means that the ethanol produced from such facilities cannot generate RINs.

For facilities that produce ethanol and for which construction commenced after December 19, 2007, section 210 of EISA states that ''for calendar years 2008 and 2009, any ethanol plant that is fired with natural gas, biomass, or any combination thereof is deemed to be in compliance with the 20% threshold.'' We refer to these facilities as ''deemed compliant.'' This provision does not specify whether such facilities are deemed to be in compliance only for the period of 2008 and 2009, or indefinitely. Nor does EISA specify a date by which such qualifying facilities must have started operation. Although the Act is unclear as to whether their special treatment is only for 2008/2009, or for a longer time period, we believe that it would be a harsh result for investors in these new facilities, and generally inconsistent with the energy independence goals of EISA, for these new facilities to only be guaranteed two years of participation in the RFS2 program. We propose that the statute be interpreted to mean that fuel from such qualifying facilities, regardless of date of startup of operations, would be exempt from the 20% GHG threshold requirement for the same time period as facilities that commence construction prior to December 19, 2007, *provided* that such plants commence construction prior to December 31, 2009, complete such construction in a reasonable amount of time, and continue to burn only natural gas, biomass, or a combination thereof. Therefore, we believe that they should be treated like grandfathered facilities. We seek comment, however, on the alternative in which after 2009, such plants must meet the 20% threshold in order to generate RINs for renewable fuel produced.

Based on our survey of ethanol plants in operation, as well as those not yet in operation but which commenced construction prior to December 19, 2007, it is likely that production capacity of ethanol from all such facilities will reach 15 billion gallons. (See Section 1.5.1.4 of the DRIA.) This volume of ethanol will be excluded from having to meet the 20% GHG threshold by the grandfathering and deemed compliant provisions of EISA.[8] For ease of reference, we will refer to both these provisions as the ''exemption provisions'' of EISA.

EISA does not define the term ''new facility'' and, as mentioned above, does not clarify whether ''deemed compliant'' facilities have that status for only 2008 and 2009, or for a longer time period. EPA seeks, in interpreting these terms, to avoid long-term backsliding with respect to environmental performance and to also provide a level playing field for future investments. Thus, we want to avoid incentives that would allow overall GHG performance to worsen via expansion at older plants with poorer GHG performance or by modifications such as switches to more polluting process heat sources, such as coal. At the same time, we also want to offer protection for historical business investments that were made prior to enactment of EISA, and we want future significant investments to meet the GHG reduction standards of the Act. Finally we want to avoid excessive case-by-case decision making where possible, and seek instead a rule that offers ease of implementation while providing certainty to EPA and the regulated industry.

We are proposing one basic approach to the exemption provisions and seeking comment on five additional options. In fashioning the basic proposal and alternative options for exempted facilities, we considered aspects of exemption approaches elsewhere in the CAA and EPA regulations to evaluate whether they would foster the above-described objectives. We are only looking to these other provisions for guidance and are not bound to follow any already-established approach for a different statutory provision (especially as those other provisions may contain definitions that Congress did not incorporate here).

a. Definition of Commence Construction

In defining ''commence'' and ''construction'', we wanted a clear designation that would be broad enough to avoid facility-specific issues, but narrow enough to prevent new facilities (i.e., post-December 19, 2007) from being grandfathered. We believe that the definitions of ''commence'' and ''Begin actual construction'' in the Prevention of Significant Deterioration (PSD) regulations, which draws upon definitions in the Clean Air Act, served this purpose. (40 CFR 52.21(b)(9) and (11)). Specifically, under the PSD regulations, ''commence'' means that the owner or operator has all necessary preconstruction approvals or permits and either has begun a continuous program of actual on-site construction to be completed in a reasonable time, or entered into binding agreements which cannot be cancelled or modified without substantial loss.'' Such activities include, but are not limited to, ''installation of building supports and foundations, laying underground pipe work and construction of permanent storage structures.'' We have added language to the definition that is currently not in the PSD definition with respect to multi-phased projects. We are proposing that for multi-phased projects, commencement of construction of one phase does not constitute commencement of construction of any later phase, unless each phase is ''mutually dependent'' on the other on a physical and chemical basis, rather than economic.

The PSD regulations provide additional conditions beyond what constitutes commencement. Specifically, the regulations require that the owner or operator ''did not discontinue construction for a period of 18 months or more and completed construction within a reasonable time.'' (40 CFR 52.21(i)(4)(ii)(c). While ''reasonable time'' may vary depending on the type of project, we believe that with respect to renewable fuel facilities, a reasonable time to complete construction is no greater than 3 years from initial commencement of construction. We seek comment on the use of these definitions.

b. Definition and Boundaries of a Facility

We propose that the grandfathering and deemed compliant exemptions apply to ''facilities.'' Our proposed definition of this term is similar in some respects to the definition of ''building, structure, facility, or installation'' contained in the PSD regulations in 40 CFR 52.21. We have modified the definition, however, to focus on the typical renewable fuel plant. We therefore propose to describe the exempt ''facilities'' as including all of the activities and equipment associated with the manufacture of renewable fuel which are located on one property and under the control of the same person or persons.

c. Options Proposed in Today's Rulemaking

We are proposing one basic approach to the grandfathering provisions and seeking comment on five additional options. The basic approach would provide an indefinite extension of grandfathering and deemed compliant status but with a limitation of the exemption from the 20% GHG threshold to a baseline volume of renewable fuel. The five additional options for which we seek comment are: (1) Expiration of exemption for grandfathered and ''deemed compliant'' status when facilities undergo sufficient changes to

[8] The grandfathering and deemed compliant provisions in EISA sections 202 and 210 do not apply to the advanced biofuels, biomass-based diesel or cellulosic biofuel standards for which the Act requires a 50 or 60% GHG reduction threshold to be met regardless of when the facilities producing such fuels are constructed.

be considered ''reconstructed''; (2) Expiration of exemption 15 years after EISA enactment, industry-wide; (3) Expiration of exemption 15 years after EISA enactment with limitation of exemption to baseline volume; (4) ''Significant'' production components are treated as facilities and grandfathered or deemed compliant status ends when they are replaced; and (5) Indefinite exemption and no limitations placed on baseline volumes.

i. Basic Approach: Grandfathering Limited to Baseline Volumes

We are proposing and seeking comments on an option which generally limits the volume of any renewable fuel for which a grandfathered and deemed compliant facility can generate RINs without complying with the 20% GHG reduction threshold to the capacity volume specified in a state or Federal air permit or the greater of nameplate capacity or actual production. This approach is similar to how we have treated small refiner flexibilities under our other fuel rules. As a sub-option to this approach, we also seek comment on a provision whereby facilities would lose their status if they switch to a process fuel or feedstock which results in an increase of GHG emissions.

(1) Increases in Volume of Renewable Fuel Produced at Grandfathered Facilities due to Expansion

For facilities that commenced construction prior to December 19, 2007, we are proposing to define the baseline volume of renewable fuel exempt from the 20% GHG threshold requirement to be the maximum volumetric capacity of the facility as allowed in any applicable state air permit or Federal Title V operating permit. If the capacity of a facility is not stipulated in such air permits, then the grandfathered volume is the greater of the nameplate capacity of the facility or historical annual peak production prior to enactment of EISA. Volumes greater than this amount which may typically be due to expansions of the facility which occur after December 19, 2007, would be subject to the 20% GHG reduction requirement in order for the facility to generate RINs for the incremental expanded volume. The increased volume would be considered as if produced from a ''new facility'' which commenced construction after December 19, 2007. Changes that might occur to the mix of renewable fuels produced within the facility would remain grandfathered as long as the overall volume fell within the baseline volume.

The baseline volume would be defined as above for deemed compliant facilities with the exception that if the maximum capacity is not stipulated in air permits, then the exempt volume would be the maximum annual peak production during the plant's first three years of operation. In addition, any production volume increase that is attributable to construction which commenced prior to December 31, 2009 would be exempt from the 20% GHG threshold, provided that the facility continued to use natural gas, biomass or a combination thereof for process energy. Because deemed compliant facilities owe their status to the fact that they use natural gas, biomass or a combination thereof for process heat, we propose that their status would be lost, and they would be subject to the 20% GHG threshold requirement, at any time that they change to a process energy source other than natural gas and/or biomass. Finally, because EISA limits deemed compliant facilities to ethanol facilities, we propose that if there are any changes in the mix of renewable fuels produced by the facility that only the ethanol volume remain grandfathered. We solicit comment, however, on whether the statute could be read to allow deemed compliant facilities to be treated the same as grandfathered facilities by allowing a mix of renewable fuels.

Volume limitations contained in air permits may be defined in terms of peak hourly production rates or a maximum annual capacity. If they are defined only as maximum hourly production rates, they would need to be converted to an annual rate. We believe that assuming 24-hour per day production over 365 days per year (8,760 production hours) may overstate nameplate capacity. In other regulations that pertain to refinery operations, we have assumed a conversion rate of 90% of the total hours in a year (7884 production hours). We seek comment on what would be an appropriate conversion rate for renewable fuel facilities.

The facility registration process (*see* Section III.C) would be used to define the baseline volume for individual facilities. Owners and operators would submit information substantiating the nameplate capacity of the plant, as well as historical annual peak capacity if such is greater than nameplate capacity. Subsequent expansions at a grandfathered that result in an increase in volume would subject the increase in volume to the 20% GHG emission reduction threshold (but not the original baseline volume). Thus, any new expansions would need to be designed to achieve the 20% GHG reduction threshold if the facility wants to generate RINs for that volume. Such determinations would be made on the basis of EPA-defined corn ethanol fuel pathway categories that are deemed to represent such 20% reduction. As an alternative approach to the greater of nameplate capacity or historical annual peak capacity, we seek comment on an approach in which the baseline volume is the actual volume of renewable fuel produced during the 2006 calendar year, where adequate data is available. Since there has been a particularly high demand for ethanol in recent years, the use of 2006 data may be a fair representation of the real production capacity for most plants. For plants that have not operated for an adequate shake down period, the information in the state or Federal air permit could be used and if this is not available, the nameplate capacity could be used. As mentioned above, deemed compliant facilities would be exempt from the 20% GHG threshold for baseline volumes and any additional volumes regarding which construction commenced prior to December 31, 2009.

We recognize, however, that some debottlenecking type changes may cause increases in volume that are within a plant's inherent capacity. To account for this in past regulations (e.g., 40 CFR 80.552 and 554) we allowed for an increase of 5% above the baseline volume. Based on conversations with builders of ethanol plants, however, such plants have often been debottlenecked to exceed nameplate capacity by 20% and sometimes much higher. We seek comment on whether we should allow a 10% tolerance on the baseline volume for which RINs can be generated without complying with the 20% GHG reduction threshold. Once that 10% increase in volume is exceeded, the total increase above baseline volume would then be subject to the 20% GHG reduction requirement in order to generate RINs. We also seek comment on tolerance values in the 5 to 20% range.

Our guiding philosophy of protecting historical business investments that were made to comply with the provisions of RFS1 is realized by allowing production increases within a plant's inherent capacity. At the same time, the alternative of requiring compliance with the 20% GHG reduction requirement for increases in volume above 10% over the baseline volume, would place new volumes from grandfathered facilities on a level playing field with product from new grass roots facilities. We believe that a level playing field for new investments is fair and consistent with the provisions of EISA.

(2) Replacements of Equipment

If production equipment such as boilers, conveyors, hoppers, storage tanks and other equipment are replaced, it would not be considered construction of a ''new facility'' under this option of today's proposal—the baseline volume of fuel would continue to be exempt from the 20% GHG threshold. We discuss in a sub-option in III.B.3.c.i(4) below in which if the replacement unit uses a higher polluting fuel in terms of GHG emissions such replacement would render the facility a new facility, and it would no longer be exempt from the 20% GHG threshold. We also solicit comment on an approach that would require that if coal-fired units are replaced, that the replacement units must be fired with natural gas or biofuel for the product to be eligible for RINs that do not satisfy the 20% GHG threshold.

(3) Registration, Recordkeeping and Reporting

Facility owner/operators would be required to provide evidence and certification of commencement of construction. Owner/operators must provide annual records of process fuels used on a BTU basis, feedstocks used and product volumes. For facilities that are located outside the United States (including outside the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands) owners would be required to provide certification as well. Since the definition of commencement of construction includes having all necessary air permits, we would require that facilities outside the United States to certify that such facilities have obtained all necessary permits for construction and operation required by the appropriate national and local environmental agencies.

(4) Sub-Option of Treatment of Future Modifications

We seek comment on a sub-option to the basic approach whereby facilities would lose their grandfathered status if they switch to a process fuel or feedstock which results in an increase of GHG emissions. Some facilities may keep production volumes the same, but change some or all of their feedstocks and energy sources, thus causing a facility's product to fall further below the GHG performance for the fuel pathway it produced at the time of enactment. We are therefore seeking comment on an approach to limit the initial grandfathering only for the fuel pathways that applied during 2007, when establishing the volume baseline. Table III.B.3.c.i–1 below presents a ranking of fuels and feedstock by fuel pathway in order of life cycle GHG emissions (as discussed further in Section VI.E). (Table III.B.3.c.i–1 is based on the table of fuel pathways contained in proposed regulations 40 CFR 80.1426.) Since the majority of facilities under consideration in this portion of the rulemaking consists of ethanol plants, the table below is limited to those types. Any changes to a facility that shift it to a feedstock or use of a process energy source that results in higher GHG emissions on the basis of the ranking categories in Table III.B.3.c.i–1 below would terminate the facility's grandfathered status.

For example, an ethanol dry mill plant using natural gas for process heat, as well as combined heat and power (CHP), is ranked as ''2'' in the table below. If the plant (or any portion of the plant) switches to coal, it is ranked as ''4''. The higher number indicates an increase in GHG emissions. Therefore in this example, the plant is considered to have undertaken a modification that increases GHG emissions, would render the facility as ''new'' and its grandfathered status would end. Similarly, replacements of equipment that worsen GHG emissions would also terminate grandfathered status. (For replacements of equipment that do not change the fuel, nor result in an increase in volume of renewable fuel, the grandfathered status of the plant would remain, as discussed in Section III.B.3.c.i(2) above.)

TABLE III.B.3.c.i–1—GROUPS OF RENEWABLE FUEL FACILITIES BY FUEL FEEDSTOCK AND PROCESS ENERGY

Feedstock	Production process requirements	Ranking
Starch from corn, wheat, barley, oats, rice, or sorghum	—Process heat derived from biomass	1
Starch from corn, wheat, barley, oats, rice, or sorghum	—Dry mill plant —All process heat derived from natural gas. —Combined heat and power (CHP). —Fractionation of feedstocks. —Dried distillers grains.	2
Starch from corn, wheat, barley, oats, rice, or sorghum	—Dry mill plant —All process heat derived from natural gas. —Wet distillers grains.	3
Starch from corn, wheat, barley, oats, rice, or sorghum	—Dry mill plant —All or part of process heat derived from coal. —Combined heat and power (CHP). —Fractionation of feedstocks. —Membrane separation of ethanol. —Raw starch hydrolysis. —Dried distillers grains.	4
Starch from corn, wheat, barley, oats, rice, or sorghum	—Dry mill plant —All or part of process heat derived from coal. —Combined heat and power (CHP). —Fractionation of feedstocks. —Membrane separation of ethanol. —Wet distillers grains.	5
Sugarcane sugar	—Process heat derived from sugarcane bagasse	1
Sugarcane sugar	—Process heat derived from natural gas	2
Sugarcane sugar	—Process heat derived from coal	3

We considered whether improvements at a facility (i.e., a fuel switch from coal to natural gas) that still result in GHG performance less than 20% should be credited to allow the facility to increase its baseline volume. We decided not to propose such an approach because it would take away an incentive for new plants that achieve greater than 20% GHG reduction to be constructed. As such, this would go against our guiding principle of providing equal opportunities for future investments in new plants.

We recognize that there may be combinations of changes made at a plant, some of which may worsen GHG emissions and others which may cause an improvement and that not all such combinations can be taken into account in a single table of fuel pathways. We seek comment on ways to address such combinations.

ii. Alternative Options for Which We Seek Comment

(1) Facilities That Meet the Definition of ''Reconstruction'' Are Considered New

An alternative approach on which we are seeking comment would consider whether a facility is effectively a ''new'' facility with respect to the costs incurred in maintaining the plant over time. Starting in 2010, we would require facility owners to report annually (specifically by January 31) to EPA the expenses for replacements, additions, and repairs undertaken at facilities since start up of the facility through the year prior to reporting. The Agency would then determine whether the degree of such activities warrants considering the facility as effectively ''new''. That substantial rebuilding or modernization may render an existing facility a new facility for regulatory purposes finds analogies in other Clean Air Act regulatory programs. For example, under the New Source Performance Standards (NSPS) equipment that has been ''reconstructed'' as defined in 40 CFR 60.15 is considered new. Specifically, ''reconstruction'' is defined in 40 CFR 60.15 as ''the replacement of components of an existing facility to such an extent that the fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable entirely new facility. In addition to the NSPS program, regulations such as the recently promulgated standards for locomotive and marine engines (73 FR 25160; May 6, 2008) use a more encompassing concept of reconstruction and consider a vessel to be new if it is modified such that the value of the modifications exceeds 50% of the value of the modified vessel. We are seeking comment on an approach wherein upon the Agency's determination that costs of replacements, repairs and upgrades conducted since the start-up of the facility meet the test of ''reconstruction'' (i.e., the costs equal or exceed 50% of what it would cost to rebuild), that the facility would be considered effectively new, and would be subject to the 20% GHG reduction requirements.

The application of the definition of reconstruction in the NSPS program occurs on an equipment-wide rather than on a plant-wide basis. Under this option, we would apply the concept of a ''new'' facility on a plant-wide basis similar to the approach we have taken in the recently promulgated locomotive and marine standards. We believe that a plant-wide approach is appropriate under RFS2 because it is not the emissions from individual pieces of equipment that are being regulated. Rather, the 20% GHG reduction standard applies to the renewable fuel produced by the facility, and it is logical to consider all of the equipment and structures at the facility involved in producing the product in evaluating when a grandfathered facility has been reconstructed. For these reasons, we believe that it would be reasonable to apply the definition of ''new'' on a plant-wide basis. Also, since upgrades, replacements and repairs will occur on an ongoing basis we would consider rebuilding or reconstruction to occur over time as the accumulation of all individual upgrades, replacements and repairs.

The NSPS definition also requires that it be ''technologically and economically feasible for the reconstructed facility to meet applicable standards that apply to new facilities.'' We do not think that EISA requires this additional consideration, and also do not believe that there is any compelling public policy justification for allowing a reconstructed facility to continue to make renewable fuel that does not meet the 20% GHG reduction standard based upon a claim that it is technologically or economically infeasible. EPA's experience in the New Source Review (NSR) program has demonstrated that it is extremely difficult to clearly define what the terms ''technologically and economically feasible'' mean. Aside from such definitional difficulties, however, and as discussed in Section III.B.3.c.ii(2) below, we believe that it is technologically feasible to meet the 20% GHG reduction and with proper planning would be economically so, as well. Therefore, this alternative option would not require such a showing.

Our assessment of whether a facility has been reconstructed would be based on application of an appropriate cost model such as U.S. Department of Agriculture's cost estimation model for construction of new ethanol plants described by Kwiatkowski, J. et al. (2006) [9]. Costs associated with the costs of repair and replacement of all parts (including the labor associated with replacement and repair), would be included in such calculation, regardless of the parts' intended useful life. We seek comment on whether to also include costs associated with employee labor related to routine maintenance, and also whether the costs of repairs and replacements at the facility should be limited only to the property directly related to the production of biofuels.[10]

Under this alternative option, the volume of renewable fuel that qualifies for an exemption from the 20% GHG threshold would remain fixed at the baseline volume as in the basic option described in III.B.3(c)(i). However, we also seek comment on whether the volume of renewable fuel at a grandfathered facility should be allowed to increase above baseline volumes under this option. Specifically, increases in volume could be exempt until such time as the entire plant is deemed to have been reconstructed. In making such assessment and applying the 50% test, the basis for the cost of a ''comparable entirely new facility'' would be a facility with the original baseline volume. For example, if an existing plant has a 100 million gallon per year capacity and expands its volume to 120 million gallons per year, reconstruction would occur if the costs incurred over time equal or exceed 50% of the cost of a comparable 100 million gallon per year facility.

Under this alternative option, owner/operators or other responsible parties would be required to provide records of costs incurred for additions, replacements, and repairs that have

[9] Kwiatkowski, J.R., McAloon, A., Taylor, F. Johnson, D. 2006. ''Modeling the process and costs of fuel ethanol production by the corn dry-grind process.'' *Industrial Crops and Products* 23 (2006) 288–296.

[10] We note that under NSPS the costs considered in determining whether the definition of reconstruction has been met are restricted to the capital costs of equipment and materials. The RFS2 program is authorized from EISA which does not rely on the definitions of ''modification'' and ''routine maintenance and repair'' that are in NSPS and other new source programs (e.g., New Source Review, National Emission Standards for Hazardous Pollutants). Since our application of the term ''reconstruction'' assumes that over time, renewable fuel facilities may become substantially rebuilt it is therefore appropriate to consider not only equipment replacements but some of the labor costs associated with such replacements.

occurred since start-up. Such records would be provided on an annual basis to EPA by May 31, and would include cumulative cost information up to the prior year.

We recognize that implementation of a facility-wide definition of ''reconstruction'' would be complex. Records of costs since start-up may not be available for older facilities. Also, this alternative option requires EPA enforcement staff to have sufficient financial knowledge and experience to be able to evaluate the veracity of claims regarding various types of expenditures. Calculating the costs of repairs and replacements also poses challenges. Specifically, as discussed above, we seek comment on whether the costs of routine maintenance and repair should be included in such assessments. Were such costs to be included, the determination of whether a replacement or a repair is routine may not always be straightforward. In addition to the recordkeeping and implementation issues, however, there is an important policy consideration that is also significant. As in the case of the NSR program, where many industry representatives have argued that the program has a chilling effect on projects that could provide environmental benefits, the reconstruction approach in this alternative option could also provide a disincentive to implementation of safety and environmental projects. Thus, this option could have the unintended consequence of causing facilities to refrain from investing in projects that will increase safety and efficiency and reduce emissions in order to avoid triggering the 50% cost threshold. We seek comment on this issue.

(2) Expiration Date of 15 Years for Exempted Facilities

The above discussion highlights potential complexities in implementing the option of considering reconstruction of exempted facilities on a case-by-case basis. These include potential disputes over how to calculate costs, as well as verifying records of expenditures. In addition, that option has as a potential unintended consequence, a disincentive for investment in projects that could improve safety, efficiency and environmental performance. As an alternative to the case-by case approach described above, this option offers a practical way of implementing the reconstruction concept by establishing an expiration date for all grandfathered and deemed compliant facilities after a period of 15 years from enactment of EISA (i.e., after December 31, 2022), regardless of when such facilities commenced construction or began operation. Under such option, the grandfathered and deemed compliant facilities would be subject to the 20% GHG threshold starting on January 1, 2023. Renewable fuel produced from these facilities after this date would be required to comply with the 20% threshold requirement in order to generate RINs.

Based on our discussions with companies that construct ethanol plants, we believe that facility owners will make decisions about equipment replacements and technology upgrades that will continue to improve the overall operating costs and energy efficiency of the plant which ultimately lead to improvements in GHG emission performance as well. In particular, energy-intensive processes in the plant are likely to be replaced or upgraded to increase fuel and operating efficiency, thus reducing operating costs of the plant, and increasing output. Nilles (2006) reports that the first line of next-generation dry-grind ethanol plants was built with mild steel components and that in 10 or 15 years, those components will need to be replaced entirely—most likely with stainless steel. Of particular importance is that durable materials as well as weaker materials all require maintenance and replacement. As such, the components and equipment in ethanol facilities are designed to be easily replaced and to allow simple maintenance.[11]

Using cost data contained in the U.S. Department of Agriculture's cost estimation model for construction of new ethanol plants described by Kwiatkowski, J. et al (2006), we calculated the cost of a replacement of specific components in a hypothetical 100 million gallon ethanol facility.[12] [13] We assumed that all steel tanks are replaced with stainless steel tanks, and that specific combustion equipment is replaced. Combining replacement costs with maintenance, repairs, upgrades and supply costs (at 2% of the capital cost of the facility per year), we calculated that over 15 years, the accumulated costs range from 50% to 75% of the capital cost of an equivalent facility.[14]

As discussed in Section 1.5.1.3 of the DRIA, per our conversations with builders of ethanol plants, the changes and upgrades would be made to improve competitiveness which will also improve operating and fuel efficiency, thus tending to improve overall GHG performance of the plant. The high price of natural gas has many ethanol plants considering alternative fuel sources. Greater biofuel availability and potential low life cycle green house gas emissions incentives may further encourage ethanol producers to switch from fossil fuels for process heat to biomass based fuels. In addition, ethanol producers may consider energy saving changes to the ethanol production process. Several process changes, including raw starch hydrolysis, corn fractionation, corn oil extraction, and membrane separation, are likely to be adopted to varying degrees. Since such changes would be consistent with ultimately achieving the 20% GHG reduction required of new facilities, we believe it is reasonable to expect that the newly rebuilt facilities could meet the 20% GHG reduction threshold, based on the results of a life cycle analysis.[15]

We solicit further information and data, particularly evidence of the types of replacements and ongoing maintenance that has occurred at existing plants and what is projected to occur in the future. We will evaluate such information along with other comments received during the public comment period. We also solicit comment on whether a period other than 15 years may be more appropriate.

Under this approach, facilities that are exempted could expand their volume of renewable fuel production, or could switch fuels or feedstocks within the 15 year exemption period without fear of losing their temporary exemption. While some of these activities have the potential to worsen GHG emissions further below the 20% threshold requirement, we believe that the imposition of an expiration date will result in modifications to facilities that tend to increase the efficiency and GHG performance of the plant rather than worsen them. The need for compliance with the 20% threshold requirement by a date certain would provide an incentive for owners and operators of

[11] Nilles, D. 2006. ''Time Testing''; Ethanol Producer Magazine, May, Vol. 12, No. 5.

[12] Op Cit., Kwiatkowski, *et al.* (2006).

[13] Note to Docket (EPA–HQ–OAR–2005–0161), ''Analysis of Costs of Replacements and Repairs at a Hypothetical 100 MM GPY Ethanol Facility''; from Barry Garelick, Environmental Protection Specialist, Assessment and Standards Division, Office of Transportation and Air Quality; October 16, 2008.

[14] The USDA model gives the installed capitol cost of a 40 million GPY facility at approximately $60 million (2006 dollars). The model also gives replacement costs of individual components (steel tanks and the ring dryer) at about $13 million. Ongoing maintenance costs are estimated at about $6 million per year.

[15] Unless and until EPA conducts facility specific life cycle analyses, however, compliance with the 20% GHG reduction threshold would be made on the basis of fuel pathways as described in Section III.D.2.

such plants to ensure the changes they make over time would bring them into compliance with the 20% requirement at the end of the 15 year period.

While the facilities built in 2008 and 2009 would be in operation for less than 15 years, the majority of ethanol plants will have been in operation for 15 years or longer. As discussed in Section V.B.1, approximately 15 billion gallons of corn ethanol production capacity is currently online, idled or under construction. While some of these plants/projects are currently on hold due to the economy, we anticipate that this corn ethanol capacity will come online in the future under the proposed RFS2 program. And the majority of these plants commenced construction prior to 2008. We solicit comment, however, on whether there should be a plant-specific expiration date of 15 years after commencement of operations for deemed compliant facilities that commenced construction in 2008 or 2009. Under this sub-option, the expiration date for such plants would be 15 years from the time the facility began operation, per registration made by the owner of the facility.

The option of limiting the exemption period to 15 years or other specific time period offers certainty to industry for a 15 year period, and also certainty that at the end of that time period they will be subject to the 20% GHG reduction threshold. This time period could be used by facility owners to ensure the facility will ultimately meet the requirement. Finally, the option ensures that investments made in equipment to comply with RFS1 requirements are protected with respect to being fully depreciated for tax purposes.[16] Furthermore, this approach is easy to implement, and avoids case-by-case determinations that can extremely be time-consuming, contentious, and costly for both industry and EPA. In addition, because the exemption expiration date would apply to all facilities, this option would provide no incentive to delay modifications that increase energy efficiency, safety, or improve environmental performance unlike the option described above involving case-by-case consideration of reconstruction.

[16] Specifically, Table B–2 of IRS Publication 946, ''How To Depreciate Property'' provides class lives and recovery periods for use in computing depreciation for asset classes categorized by SIC codes. Ethanol facilities (which are in SIC 28, Manufacture of Chemical and Allied Products) is given a class life of 10 years. For facilities that qualify for Modified Accelerated Cost Recovery System (MACRS), the period is 7 years.

(3) Expiration Date of 15 Years for Grandfathered Facilities and Limitation on Volume

We also seek comment on a hybrid approach in which an expiration date of 15 years is established for grandfathered and deemed compliant facilities, but prior to then, the facilities' exemption from the 20% GHG threshold would be limited to their baseline volumes, as in the option described in Section III.B.3.c.

(4) ''Significant Production Units'' Are Defined as Facilities

We seek comment on an approach in which ''facility'' would be defined on the basis of ''significant production units''. For example, the regulations regarding air toxic emissions for the miscellaneous organic chemical manufacturing industry (which includes ethanol manufacturing plants) under NESHAPS (40 CFR 2440(c)) apply to miscellaneous chemical process units and heat exchangers within a single facility. This option, therefore, would follow a similar approach, and treat as new facilities subject to the 20% GHG reduction requirement any new significant production units.

Defining ''facility'' as a significant production unit would raise the question of when an increase in volume due to the addition of specific pieces of equipment should be considered augmenting current production lines as opposed to being a new production line. We solicit comment on this approach as well as how the term ''significant production unit'' would need to be defined in the regulations to avoid ambiguity. Any incidental increases in volume due to the addition of pieces of equipment that would not constitute a new ''significant production unit'' line would continue to be grandfathered, as would increases in volume associated with changes made to debottleneck the facility.

(5) Indefinite Grandfathering and No Limitations Placed on Volume

Under our basic option, described in Section III.B.3.c.i, we would interpret the statutory language to mean that expansions of grandfathered facilities after enactment of EISA and which expand volume beyond a plant's inherent capacity are not among those that qualify for an exemption from the 20% GHG reduction requirement. Otherwise, a facility that qualifies for grandfathering could be expanded by any amount, and the additional volume would also receive protection. We do not believe that this was the intent of the language in EISA. Nevertheless, we recognize that there are alternative interpretations of the statute and therefore seek comment on an alternative that places no limitations on the volume of renewable fuel from grandfathered or deemed compliant facilities. Under such option, ''new facility'' would be defined solely as a new ''greenfield'' plant.

4. Renewable Biomass With Land Restrictions

As explained in Section III.B.1.a, EISA lists seven types of feedstock that qualify as ''renewable biomass'':

1. Planted crops and crop residue.
2. Planted trees and tree residue.
3. Animal waste material and animal byproducts.
4. Slash and pre-commercial thinnings.
5. Biomass obtained from the vicinity of buildings at risk from wildfire.
6. Algae.
7. Separated yard or food waste.

EISA limits not only the types of feedstocks that can be used to make renewable fuel, but also the land that several of these renewable fuel feedstocks may come from. Specifically, EISA's definition of renewable biomass incorporates land restrictions for planted crops and crop residue, planted trees and tree residue, slash and pre-commercial thinnings, and biomass from wildfire areas. EISA does not prohibit the production of renewable fuel feedstock that does not meet the definition of renewable biomass, nor does it prohibit the production of renewable fuel from feedstock that does not meet the definition of renewable biomass. It does, however, prohibit the generation of RINs for renewable fuel made from feedstock that does not meet the definition of renewable biomass, which includes not meeting the associated land restrictions. The following sections discuss the challenges of implementing the land restrictions contained in the definition of renewable biomass and propose approaches for establishing a workable implementation scheme.

a. Definitions of Terms

EISA's descriptions of four feedstock types noted above—planted crops and crop residue, planted trees and tree residue, slash and pre-commercial thinnings, and biomass from wildfire areas—contain terms that can be interpreted in multiple ways. The following sections discuss our proposed interpretations for many of the terms contained in EISA's definition of renewable biomass. In developing this proposal, we consulted many sources, including the USDA, as well as stakeholder groups, in order to determine the range of possible interpretations for these different terms. We have made every attempt to define these terms as consistently with USDA and industry standards as possible, while keeping them workable for purposes of program implementation. We seek comment on our proposed definitions of important terms in the following sections.

i. Planted Crops and Crop Residue

The first type of renewable biomass described in EISA is planted crops and crop residue harvested from agricultural land cleared or cultivated at any time prior to December 19, 2007, that is either actively managed or fallow, and nonforested. We propose to interpret the term ''planted crops'' to include all annual or perennial agricultural crops that may be used as feedstock for renewable fuel, such as grains, oilseeds, and sugarcane, as well as energy crops, such as switchgrass, prairie grass, and other species, providing that they were intentionally applied to the ground by humans either by direct application as seed or nursery stock, or through intentional natural seeding by mature plants left undisturbed for that purpose. Many energy crops that could be used for cellulosic biofuel production, especially perennial cover plants, are currently grown in the U.S. without significant agronomic inputs such as fertilizer, pesticides, or other chemical treatment. These crops may be introduced or indigenous to the area in which they grow, and may have been originally planted decades ago. We propose to include this type of vegetation as a planted crop with the recognition that it may include some plants that were intentionally naturally generated, i.e., resulted from natural seeding from existing plants, and not planted through direct human intervention. We believe that given the increasing importance under RFS2 of biofuels produced from cellulosic feedstocks, such as switchgrass and other grasses, such a definition is appropriate. We note that because EISA contains specific provisions for planted trees and tree residue from tree plantations, we propose that the definition of planted crops in EISA exclude planted trees, even if they may be considered planted crops under some circumstances.

We further propose that ''crop residue'' be limited to the residue left over from the harvesting of planted crops, such as corn stover and sugarcane bagasse. However, we seek comment on an alternative interpretation that would include as crop residue biomass from agricultural land removed for purposes of invasive species control or fire management. In that context ''crop residue'' would include any biomass removed from agricultural land that facilitates crop management, whether or not the crop itself is part of the residue.

Our proposed regulations would restrict planted crops and crop residue to that harvested from existing agricultural land. With respect to what land would qualify as agricultural land, we first turned to the mutually exclusive categories of land defined by USDA's Natural Resources Conservation Service (NRCS) in its annual Natural Resources Inventory (NRI), a statistical survey designed to estimate natural resource conditions and trends on non-federal U.S. lands.[17] The categories used in the NRI are cropland, pastureland, rangeland, forest land, Conservation Reserve Program (CRP) land, federal land, developed land, and ''other rural land.'' We have chosen to include in our proposed definition of agricultural land three of these land categories—cropland, pastureland, and CRP land. Using the NRI descriptions of these land types as models, we developed definitions for these land types for this proposal.

We propose to define cropland as land used for the production of crops for harvest, including cultivated cropland for row crops or close-grown crops and non-cultivated cropland for horticultural crops. Corn, wheat, barley, and soybeans are renewable fuel feedstocks that would be grown on cropland. We propose to define pastureland as land managed primarily for the production of indigenous or introduced forage plants for livestock grazing or hay production, and to prevent succession to other plant types. Under this proposed definition, land would qualify as pastureland if it is maintained for grazing or hay production and not allowed to develop greater ecological diversity. Switchgrass is one example of a renewable fuel feedstock that could be grown on pastureland.

We also propose that CRP land be counted as ''agricultural land'' under RFS2. The CRP is administered by USDA's Farm Service Agency and is designed to promote restoration of environmentally sensitive lands by offering annual rental payments in return for removing land from cultivation over a period of several years. To qualify for the CRP, land had to have been used for agricultural production for at least three years prior to entering the program. For this reason, we believe it is appropriate to propose that CRP land be included under the rubric of agricultural land.

In addition, we seek comment on whether rangeland should be included as agricultural land under RFS2. Rangeland is land on which the indigenous or introduced vegetation is predominantly grasses, grass-like plants, forbs or shrubs and which—unlike cropland or pastureland—is predominantly managed as a natural ecosystem. Given the relative lower degree of management of such lands, it is questionable whether any rangeland should qualify as ''actively managed'' under EISA (a general discussion on our proposed interpretation of the term ''actively managed'' is presented later in this section). On the other hand, we understand that there is frequently some degree of management on such lands, such as controlling invasive species, managing grazing rates, fencing, etc.

Therefore, we believe that there may be merit in allowing planted crops and crop residue from rangeland to qualify as renewable biomass under this program. This would allow, for example, existing switchgrass or native grasses on rangeland to be used for renewable fuel production that qualifies for RIN generation under this program. However, we are not proposing to include rangeland as agricultural land due to our own implementation concerns as well as issues raised by stakeholders over the potential for providing any incentive for increased crop production in rangeland areas. We seek comment on the issue and on the points raised in the following discussion.

Allowing rangeland to qualify as agricultural land under RFS2 would make millions of acres of additional non-cropland, non-forested land qualify for renewable fuel feedstock production in the U.S. This additional land could be important to support future expansion of dedicated energy crops, such as switchgrass and tall prairie grass, which currently grow or could grow on such lands. The availability of rangeland could alleviate some of the competition on cropland and pastureland for space to grow crops for biofuel feedstocks, thereby allowing continued growth of food crops on land best suited for that specific purpose. It would also provide rangeland owners with the potential for increased revenues from their lands by producing feedstocks for renewable fuel, and decrease the pressure for such lands to be converted to cropland for food crop production.

[17] Natural Resource Conservation Service, USDA, ''Natural Resources Inventory 2003 Annual NRI,'' February 2007. Available at *http://www.nrcs.usda.gov/technical/NRI/2003/Landuse-mrb.pdf.*

However, we recognize that rangeland is a term that can be used to describe a wide variety of ecosystems, including certain grasslands, savannas, wetlands, deserts, and even tundra. These types of ecosystems represent land that at best could serve only marginally well for producing renewable fuel feedstocks, and at worst could suffer significantly if intensive agricultural practices were imposed upon them for purposes of producing crops. We also recognize that if we were to include rangeland as agricultural land under RFS2, there is a risk that some rangeland, including native grasslands and shrublands, could be converted to produce monoculture crops. We raise these concerns for two reasons. First, certain rangeland cannot be used sustainably for agricultural crop production, and any such short-term use could seriously diminish the long-term potential of these lands to be used for less-intensive forage production or even to return to their previous ecological state. Second, conversion of relatively undisturbed rangeland to the production of annual crops could in some cases result in large releases of GHGs that have been stored in the soil. EPA believes that Congress enacted the renewable biomass definition in part to minimize GHG releases from land conversion, a goal that could be undermined by conversion of rangeland to intensive crop production under RFS2. On the other hand, it may be argued that while GHGs would be emitted initially, planting dedicated energy crops rather than food crops on such land could yield more positive than negative results over time. Such could be the case if the alternative were to grow energy crops on cropland, consequently displacing food crops to other lands, either in the U.S. or abroad. This displacement could lead to overall higher direct and indirect GHG emissions. EPA solicits comment on the potential GHG effects if rangeland were included as eligible agricultural land under RFS2. We are especially interested in data that could help us to quantify such impacts.

While enforcement of the overall renewable biomass provisions under the final RFS2 program is expected to be challenging, it is possible that including rangeland as qualifying agricultural land under the RFS2 program would increase enforcement complexity. As discussed later in this section, in order to qualify as renewable biomass under RFS2, agricultural products must come from agricultural land that was cleared or cultivated at any time prior to enactment of EISA, and either actively managed or fallow, and nonforested. We believe that evidence of past intensive use and management of rangeland may be considerably more rare, and considerably less definitive, than for other types of agricultural land. In addition, given the continuous, open nature of some rangeland, there would likely be difficulty in identifying the precise boundaries of a parcel of qualifying rangeland. EPA seeks comment on these issues.

We thus seek comment on whether or not we should include rangeland in the definition of ''existing agricultural land'' in the final RFS2 program, as well as comment on whether or not the benefits of including rangeland exceed the disadvantages. We also seek comment on how best to define rangeland, and whether we can define rangeland in a meaningful way such that sensitive ecosystems that may generally be described as rangeland can be protected from cultivation for renewable fuel feedstock production.

Furthermore, EPA solicits comment on an alternative option that would include rangeland as agricultural land, but that would interpret the EISA ''actively managed'' criterion in the renewable biomass definition (again, discussed later in this section) to limit the types of planted crops or crop residues from specific parcels of land that can qualify as renewable biomass by reference to the type of management (cropland, pastureland, or rangeland) being practiced on the date EISA was enacted. For example, if at some point in the future corn or other row crops are grown on land that was pastureland or rangeland when EISA was enacted, such row crops would not qualify as renewable biomass under RFS2. This approach could thus reduce the incentives for pastureland and rangeland owners to convert their land to cropland. We believe that this approach could have less environmental harm than allowing unrestricted use of qualifying rangeland for the production of crops for renewable fuel production.

While our proposed implementation approach and alternatives are presented later in this section, it is important to note here that the principal drawback to this alternative option involves its implementation and enforcement. This approach would require that land types (again, cropland, pastureland, or rangeland) be identified as of the date of EISA enactment in order to determine which feedstocks grown on such land would qualify as renewable biomass. In practical terms, such an approach may mean, for example, that a renewable fuel producer would need to be able to identify not only whether a given shipment of corn was grown on agricultural land cleared or cultivated prior to enactment of EISA, but also that the land was not previously pastureland or rangeland that had been converted to cropland after enactment of EISA. If it was, it would not qualify as renewable biomass. We are concerned that adding this additional feedstock verification criterion to those already contained in this proposal could render the program unworkable and unenforceable. However, we invite comment on this option, and specifically request comment on how this option could be implemented in a workable and enforceable manner.

In keeping with the statutory definition for renewable biomass, we propose to include in our definition of existing agricultural land the requirement that the land was cleared or cultivated prior to December 19, 2007, and that, since December 19, 2007, it has been continuously actively managed (as agricultural land) or fallow, and nonforested. We believe the language ''cleared or cultivated at any time'' prior to December 19, 2007, describes most cultivable land in the U.S., since so much of the country's native forests and grasslands were cleared in the 17th, 18th, and 19th centuries, if not before, for agriculture. We further believe that land that was cropland, pastureland, or CRP land on December 19, 2007, would automatically satisfy this particular criterion, and that therefore it is not of significant concern from an implementation or enforcement perspective.

In the event that we were to include rangeland as agricultural land under the final RFS2 program, satisfying the ''cleared or cultivated'' criterion could pose significant challenges. Some rangeland has never been cleared or cultivated, or may have been cleared or cultivated prior to December 19, 2007, but no evidence exists to confirm this. Therefore, we could not assume that it would necessarily meet the ''cleared or cultivated'' criterion. For instance, grasslands in the Midwest and West that during the Dust Bowl of the 1930s had been used for cultivation could meet this criterion, but other western grasslands and prairies used for cattle grazing may not. We seek comment on how best to verify that rangeland to be used for renewable fuel feedstock production was cleared or cultivated at some point prior to December 2007. We also seek comment on whether the challenge associated with applying this criterion to rangeland is sufficient (alone or combined with the concerns raised earlier about the inclusion of rangeland in the definition of agricultural land) to exclude rangeland from the final definition of agricultural land.

We believe that the more restrictive, and therefore more important, criteria is whether agricultural land is actively managed or fallow, and nonforested, per the statutory language. We propose to interpret the phrase ''that is actively managed or fallow, and nonforested'' as meaning that land must have been actively managed or fallow, and nonforested, on December 19, 2007, and continuously thereafter in order to qualify for renewable biomass production. We believe this interpretation of the legislative language is reasonable and appropriate for the following reason. The EISA language uses the present tense (''is actively managed * * *'') rather than the past tense to describe qualifying agricultural land. We interpret this language to mean that at the time the planted crops or crop residue are harvested (i.e., now or at some time in the future), the land from which they come must be actively managed or fallow, and nonforested. However, assuming that the land was cleared or cultivated at some point in time, then any land converted to agricultural land after December 19, 2007, and used to produce crops or crop residue would inherently meet the definition of ''is actively managed or fallow, and nonforested,'' and the EISA land restriction for planted crops and crop residue would have little meaning (except in cases where it could be established that the land in question had never been cleared or cultivated). We believe that in order for this provision to have meaning, we must require that agricultural land remain ''continuously'' either actively managed or fallow, and nonforested, since December 19, 2007. In this way, the upper bound on acreage that qualifies for planted crop and crop residue production under RFS2 would be limited to existing agricultural land—cropland, pastureland, or CRP land—as of December 19, 2007, and the phrase ''is actively managed or fallow, and nonforested'' would be interpreted in a meaningful way.

We propose that ''actively managed'' would mean managed for a predetermined outcome as evidenced by any of the following: sales records for planted crops, crop residue, or livestock; purchasing records for land treatments such as fertilizer, weed control, or reseeding; a written management plan for agricultural purposes; documentation of participation in an agricultural program sponsored by a Federal, state or local government agency; or documentation of land management in accordance with an agricultural certification program. Examples of government programs or product certification programs that would indicate active agricultural land management include USDA's certified organic program or the Federal Crop Insurance program.

We realize that it may be difficult to conclude that certain land has been actively managed continuously since December 2007 based solely on the existence of receipts for fertilizer or seed. However, we have included sales and purchasing records in the list of written documentation that could be used to indicate active management due to the fact that there may be qualifying land that is not registered with any formal agricultural program, for which the owner does not receive government benefits, and for which no written management plan exists (or existed as of December 2007). We believe this may be the case especially for pastureland from which no crops are harvested or sold. Other evidence that could be used regarding the consistent management of pastureland since December 2007 are records associated with the sale of livestock that grazed on the land. We seek comment on our proposal to include relevant records of sales and purchasing as adequate documentation to prove that land was actively managed since December 2007 and whether there may be other records, such as tax or insurance records, which could satisfy this requirement more effectively.

The term ''fallow'' is generally used to describe cultivated land taken out of production for a finite period of time. We believe it may be argued that fallow land is actively managed land because there is a clear purpose or goal for taking the land out of production for a period of time (e.g., to conserve soil moisture). Nonetheless, because the EISA language clearly identifies a difference between actively managed agricultural land and fallow agricultural land, we propose to define fallow to mean agricultural land that is intentionally left idle to regenerate for future agricultural purposes, with no seeding or planting, harvesting, mowing, or treatment during the fallow period. While fallow agricultural land is characterized by a lack of activity on the land, we believe that the decision to let land lie fallow is made deliberately and intentionally by a land owner or farmer such that there should be documentation of such intent. We seek comment on this assumption and on whether there are other means of verifying whether land was fallow, particularly as of December 2007. We also seek comment on whether we should specify in the regulations a time period after which land that is not actively managed for agricultural purposes should be considered to have been abandoned for agriculture (and not eligible for renewable biomass production under RFS2), as opposed to being left fallow. If specifying such a time limit is appropriate, we seek comment on what the time period should be, and if there should be a distinction between allowable fallow periods for different types of agricultural land.

Finally, in order to define the term ''nonforested,'' we first propose to define the term ''forestland'' as generally undeveloped land covering a minimum area of 1 acre upon which the predominant vegetative cover is trees, including land that formerly had such tree cover and that will be regenerated. We are also proposing that forestland would not include tree plantations. Under this proposal, ''nonforested'' land would be land that is not forestland. We believe this definition is sufficient to make distinctions between forestland and land that is considered nonforested in the field. However, we seek comment on whether we should incorporate into our definition of forestland more quantitative descriptors, such as a minimum percentage of canopy cover or minimum or maximum tree height, to help clarify what would be considered forestland. For example, the NRI definition of forestland includes a minimum of twenty-five percent canopy cover. We also seek comment on whether the one-acre minimum size designation is appropriate.

ii. Planted Trees and Tree Residue

The definition of renewable biomass in EISA includes planted trees and tree residue from actively managed tree plantations on non-federal land cleared at any time prior to December 19, 2007, including land belonging to an Indian tribe or an Indian individual, that is held in trust by the United States or subject to a restriction against alienation imposed by the United States. We propose to define the term ''planted trees'' to include not only trees that were established by human intervention such as planting saplings and artificial seeding, but also trees established from natural seeding by mature trees left undisturbed for such a purpose. We understand that, depending on the particular conditions at a plantation, certain trees in a stand may be harvested, while others are maintained, for the express purpose of naturally regenerating new trees. We believe that trees established in such a fashion, and which meet the conditions for planted trees in every other way, should not be excluded from qualifying as renewable biomass under RFS2.

Rather than using the term ''tree residue,'' we propose to use the term ''slash'' in our regulations as a more descriptive, but otherwise synonymous, term. According to the Dictionary of Forestry (1998, p. 168), slash is ''the residue, e.g., treetops and branches, left on the ground after logging or accumulating as a result of a storm, fire, girdling, or delimbing.'' We believe that this substitution will simplify our regulations, since paragraph (iv) of the EISA definition of renewable biomass also uses the term ''slash.'' Furthermore, the term ''slash'' is a common term that has a specific meaning to industry. As noted earlier, we have attempted to define terms in RFS2 using existing and commonly understood definitions to the extent possible. The term ''slash'' is more descriptive than ''tree residue,'' and yet in practice means the same thing, so we are proposing to use it rather than ''tree residue.'' We also propose to clarify that slash can include tree bark and can be the result of any natural disaster, including flooding.

In concert with our proposed definition for ''planted trees,'' we propose to define a ''tree plantation'' as a stand of no fewer than 100 planted trees of similar age and comprising one or two tree species, or an area managed for growth of such trees covering a minimum of 1 acre. Given that only trees from a tree plantation may be used as renewable biomass under RFS2, we believe that the definition should be clear and easily applied in the field. We recognize that this proposed definition is more specific than the Dictionary of Forestry's definition of ''tree plantation,'' which is ''a stand composed primarily of trees established by planting or artificial seeding.'' We seek comment on all aspects of our proposed definition of tree plantation.

We also propose to apply the same management restrictions on tree plantations as on agricultural land and to interpret the EISA language as requiring that to qualify for renewable biomass production under RFS2, a tree plantation must have been cleared at any time prior to December 19, 2007, and continuously actively managed since December 19, 2007. Similar to our proposal for actively managed agricultural land, we propose to define the term ''actively managed'' in the context of tree plantations as managed for a predetermined outcome as evidenced by any of the following: Sales records for planted trees or slash; purchasing records for seeds, seedlings, or other nursery stock; a written management plan for silvicultural purposes; documentation of participation in a silvicultural program sponsored by a Federal, state or local government agency; or documentation of land management in accordance with an agricultural or silvicultural product certification program. Silvicultural programs such as those of the Forest Stewardship Council, the Sustainable Forestry Initiative, the American Tree Farm System, or USDA are examples of the types of programs that could indicate actively managed tree plantations.

iii. Slash and Pre-Commercial Thinnings

The EISA definition of renewable biomass includes slash and pre-commercial thinnings from non-federal forestlands, including forestlands belonging to an Indian tribe or an Indian individual, that are held in trust by the United States or subject to a restriction against alienation imposed by the United States. It excludes slash and pre-commercial thinnings from forests or forestlands that are ecological communities with a global or State ranking of critically imperiled, imperiled, or rare pursuant to a State Natural Heritage Program, old growth forest, or late successional forest.

As described in Sec. III.B.4.a.i of this preamble, our proposed definition of ''forestland'' is generally undeveloped land covering a minimum area of 1 acre upon which the primary vegetative species are trees, including land that formerly had such tree cover and that will be regenerated. Also as noted in Sec. III.B.4.a.ii of this preamble, we propose to adopt the definition of slash listed in the Dictionary of Forestry. As for ''pre-commercial thinnings,'' the Dictionary of Forestry defines the act of such thinning as ''the removal of trees not for immediate financial return but to reduce stocking to concentrate growth on the more desirable trees.'' [18] Because what may now be considered pre-commercial may eventually be saleable as renewable fuel feedstock, we propose not to include any reference to ''financial return'' in our definition, but rather to define pre-commercial thinnings as those trees removed from a stand of trees in order to reduce stocking to concentrate growth on more desirable trees. We propose to include diseased trees in the definition of pre-commercial thinnings due to the fact that they can threaten the integrity of an otherwise healthy stand of trees, and their removal can be viewed as reducing stocking to promote the growth of more desirable trees. We seek comment on whether our definition of pre-commercial thinnings should include a maximum diameter and, if so, what the appropriate maximum diameter should be.

We understand that the State Natural Heritage Programs referred to in EISA are those comprising a network associated with NatureServe, a non-profit conservation and research organization. The network includes local programs in each of the 50 United States, other U.S. territories and regions including the Navajo Nation and Tennessee Valley Authority, eleven Canadian provinces and territories, and eleven Latin American countries. Individual Natural Heritage Programs collect, analyze, and distribute scientific information about the biological diversity found within their jurisdictions. As part of their activities, these programs survey and apply NatureServe's rankings, such as critically imperiled (S1), imperiled (S2), and rare (S3) to species and ecological communities within their respective borders. NatureServe meanwhile uses data gathered by these Natural Heritage Programs to apply its global rankings, such as critically imperiled (G1), imperiled (G2), or vulnerable (the equivalent of the term ''rare,'' or G3), to species and ecological communities found in multiple States or territories. We propose to prohibit slash and pre-commercial thinnings from all forest ecological communities with global or State rankings of critically imperiled, imperiled, or vulnerable (''rare'' in the case of State rankings) from being used for renewable fuel for which RINs may be generated under RFS2. We seek comment on our interpretation that the statutory language implies including global rankings determined by NatureServe, including the ranking of vulnerable (G3), in the land restrictions under RFS2 since State Natural Heritage Programs, which were explicitly referenced in EISA, do not establish global rankings.

The various state-level Natural Heritage Programs in the U.S. and abroad differ in organizational affiliation, with some operated as agencies of state or provincial government and others residing within universities or non-profit organizations. According to the NatureServe Web site, ''consistent standards for collecting and managing data allow information from different programs to be shared and combined regionally, nationally, and internationally. The nearly 800 staff from across the network are experts in their fields, and include some of the most knowledgeable field biologists and

[18] Helms, John, ed. ''The Dictionary of Forestry.'' Bethesda, MD: Society of American Foresters, 2003.

conservation planners in their regions.'' Different Natural Heritage Programs have different processes for initiating and performing surveys of ecological communities. In many cases, the programs respond to requests for environmental reviews or surveys from parties interested in specific locations, oftentimes for a fee. They do not make available for public consumption detailed information on the location of a ranked ecological community in some cases to protect the communities themselves and in other cases to protect private property interests. Additionally, the datasets maintained by different Natural Heritage Programs may not completely represent all of the vulnerable ecological communities in their respective States or territories simply due to the fact that surveys have not been performed for all areas.

NatureServe, however, interacts with each of the State Natural Heritage Programs to update their central database to include each State program's ecological community rankings. We propose to use data compiled by NatureServe and published in a special report to identify ''ecologically sensitive forestland.'' The report would list all forest ecological communities in the U.S. with a global ranking of G1, G2, or G3, or with a State ranking of S1, S2, or S3, and would include descriptions of the key geographic and biologic attributes of the referenced ecological community. The document would be incorporated by reference into the definition of renewable biomass in the final RFS2 regulations, and the effect would be to identify specific ecological communities from which slash and pre-commercial thinnings could not be used as feedstock for the production of renewable fuel that would qualify for RINs under RFS2. In the future, it may be necessary to update this list as appropriate through notice and comment rulemaking.

We will place a draft version of this document in the docket for the proposed rule as soon as it is available. EPA solicits comment both on this general incorporation-by-reference approach and on each individual listing in the document. We also seek comment on whether EPA should include in the document forest ecological communities outside of the 50 United States (such as in Canada or Latin American countries) that have natural heritage rankings of G1, G2, or G3 or S1, S2, or S3. In addition, we request comment on other ways that EPA may be able to provide the protections that Congress intended for important ecological communities with state-level rankings pursuant to a State Natural Heritage Program.

To complete the definition of ''ecologically sensitive forestland,'' we propose to include old growth and late successional forestland which is characterized by trees at least 200 years old.[19] We seek comment on this definition, including the proposed 200-year tree age, on whether we should specify a process for determining when a forest is ''characterized by'' trees of this or another age, and on other ways to identify old growth or late successional forestland.

iv. Biomass Obtained From Certain Areas at Risk From Wildfire

The EISA definition of renewable biomass includes biomass obtained from the immediate vicinity of buildings and other areas regularly occupied by people, or of public infrastructure, at risk from wildfire. We propose to clarify in the regulations that ''biomass'' is organic matter that is available on a renewable or recurring basis, and that it must be obtained from within 200 feet of buildings, campgrounds, and other areas regularly occupied by people, or of public infrastructure, such as utility corridors, bridges, and roadways, in areas at risk of wildfire. We propose to define ''areas at risk of wildfire'' as areas located within—or within one mile of—forestland, tree plantations, or any other generally undeveloped tract of land that is at least one acre in size with substantial vegetative cover.

It is our understanding that 100 to 200 feet is the minimum distance recommended for clearing trees and brush away from homes and other property in certain wildfire-prone areas, depending on slope and vegetation.[20] We propose that under RFS2, the term ''immediate vicinity'' would mean within 200 feet of a given structure or area, but we seek comment on the appropriateness of limiting the distance to within 100 feet.

A great deal of work has been done to identify communities and areas on the landscape in the vicinity of public lands that are at risk of wildfire by States in cooperation and consultation with the U.S. Forest Service, Bureau of Land Management, and other federal, State, and local agencies and tribes. In order to take advantage of this work, we seek comment on two possible implementation alternatives. The first alternative would incorporate into our definition of ''areas at risk of wildfire'' any communities identified as ''communities at risk'' through a process defined within the ''Field Guidance—Identifying and Prioritizing Communities at Risk'' (National Association of State Foresters, June 2003) and covered by a community wildfire protection plan (CWPP) developed in accordance with ''Preparing a Community Wildfire Protection Plan—A Handbook for Wildland-Urban Interface Communities'' (Society of American Foresters, March 2004) and certified by a State Forester or equivalent. We believe that it may make sense to include communities with CWPPs in the definition of ''areas at risk of wildfire'' since they represent specific areas around the U.S. that are identified and agreed upon through a public process that includes local and state representatives, federal agencies, and stakeholders. Additionally, CWPP guidelines indicate that normally three entities must mutually agree to the contents of the CWPPs: The applicable local government, the local fire department or departments, and the state entity responsible for forest management (State Forester or equivalent). As of June 2008, there were roughly 52,000 total ''communities at risk'' and 5,000 ''communities at risk'' covered by a CWPP.

We seek comment on incorporating by reference into the final RFS2 regulations a list of ''communities at risk'' with an approved CWPP. Similar to the document proposed for Natural Heritage Rankings, this document would be incorporated by reference into the definition of ''areas at risk of wildfire'' in the final RFS2 regulations. Because this list does not currently exist, EPA would be required to seek data from each State in order to assemble the document. The effect of this incorporation by reference would be to identify specific areas in the U.S. at risk of wildfire and from which biomass obtained from the immediate vicinity of buildings and other areas regularly occupied by people, or of public infrastructure, could be easily identified

[19] Old-growth forest is defined in the Dictionary of Forestry as ''the (usually) late successional stage of forest development. **Note:** Old-growth forests are defined in many ways; generally, structural characteristics used to describe old-growth forests include (a) live trees: Number and minimum size of both seral and climax dominants, (b) canopy conditions: Commonly including multilayering, (c) snags: Minimum number of specific size, and (d) down logs and coarse woody debris: Minimum tonnage and numbers of pieces of specific size. **Note:** Old-growth forests generally contain trees that are large for their species and site and sometimes decadent (overmature) with broken tops, often a variety of trees sizes, large snags and logs, and a developed and often patchy understory * * *.''

[20] *See* Cohen, Jack. ''Reducing the Wildland Fire Threat to Homes: Where and How Much?'' USDA Forest Service Gen.Tech.Rep. PSW–GTR–173. 1999. See also U.S. Federal Emergency Management Agency (FEMA) Web site *http://www.fema.gov/hazard/wildfire/index.shtm.*

and documented as renewable biomass. In the future, it may be necessary to update this list as appropriate through notice and comment rulemaking.

The second implementation approach on which we seek comment would incorporate into our definition of ''areas at risk of wildfire'' any areas identified as wildland urban interface (WUI) land, or land in which houses meet wildland vegetation or are mixed with vegetation. The concept of the WUI was established as part of the Healthy Forests Restoration Act (Pub. L. 108–148) which provided a means for prioritizing, planning, and executing hazardous fuels reduction projects on federal lands. SILVIS Lab, in the Department of Forest Ecology and Management and the University of Wisconsin, Madison, has, with funding provided by the U.S. Forest Service, mapped WUI lands based on data from the 2000 U.S. Census and U.S. Geological Survey National Land Cover Data.[21] We seek comment on whether and how best to make use of this WUI map and data to help implement the land restrictions for biomass obtained from areas at risk of wildfire under RFS2.

b. Issues Related to Implementation and Enforceability

Incorporating the new definition of renewable biomass into the RFS2 program raises issues that we did not have to consider when designing the RFS1 program. Under RFS1, the source of a renewable fuel feedstock was not a central concern, and it was a relatively straightforward matter to require all fuel made from specified renewable feedstocks to be assigned RINs. However, with the terms ''renewable fuel'' and ''renewable biomass'' being defined differently under EISA, we must consider potential issues related to implementation and enforcement to ensure that renewable fuel for which RINs are generated is produced from qualifying renewable biomass.

Our proposed approach to the treatment of renewable biomass under RFS2 is intended to define the conditions under which RINs can be generated as well as the conditions under which renewable fuel can be produced or imported without RINs. Both of these areas are described in more detail below.

i. Ensuring That RINs Are Generated Only for Fuels Made From Renewable Biomass

The effect of adding EISA's definition of renewable biomass to the RFS program is to ensure that renewable fuels are only allowed to participate in the program if the feedstocks from which they were made come from certain types of land. In the context of our regulatory program, this means that RINs could only be generated if it can be established that the feedstock from which the fuel was made came from these types of lands. Otherwise, no RINs could be generated to represent the renewable fuel produced or imported.

We have considered the possibility that land restrictions contained within the definition of renewable biomass may not, in practice, result in a significant change in agricultural practices. For example, a farmer wishing to expand his production by cutting forested land could grow feedstock for renewable fuel on his existing agricultural land and move production for food, animal feed, and fiber production to newly cultivated land. While the EISA language is fairly clear about what lands may be used for harvesting renewable fuel feedstocks, it does not specifically address the potential for switching non-feedstock crops to new lands. Our proposed options recognize the potential for this behavior but do not attempt to prohibit it as we believe doing so would be beyond our mandate under EISA. EPA believes that Congress would have specifically directed EPA to regulate this practice if they intended EPA to do so.

Another major issue we have considered is the treatment of domestically produced renewable fuel feedstocks versus imported feedstocks and imported renewable fuel, since the new EISA language does not distinguish between domestic renewable fuel feedstocks and renewable fuel and feedstocks that come from abroad. Under RFS1, RINs must be generated for imported renewable fuel by the renewable fuel importer. Foreign renewable fuel producers may not participate as producers in the program (i.e., may not generate RINs for their fuel) unless they produce cellulosic biomass or waste-derived ethanol and register with EPA. Because RFS1 does not define renewable fuel by its source, assigning RINs to imported renewable fuel under RFS1 is a straightforward responsibility of the importer.

However, under RFS2, ensuring that the feedstock used to produce imported renewable fuel meets the definition of renewable biomass presents additional challenges to designing a program that can apply to both domestic and imported renewable fuel. The options contained in today's proposal attempt to address this additional constraint, as discussed in Section III.B.4.d of this preamble.

ii. Ensuring That RINs Are Generated for All Qualifying Renewable Fuel

Under RFS1, virtually all renewable fuel is required to be assigned a RIN by the producer or importer. This requirement was developed and finalized in the RFS1 rulemaking in order to address stakeholder concerns, particularly from obligated parties, that the number of available RINs should reflect the total volume of renewable fuel used in the transportation sector in the U.S. and facilitate program compliance. The only circumstances under which a batch of fuel is not assigned a RIN in RFS1 is if the feedstock used to produce the fuel is not among those listed in the regulatory definition of renewable fuel at § 80.1101(d), the producer or importer of the fuel produces or imports less than 10,000 gallons per year, or the fuel is produced and used for off-road or other non-motor vehicle purposes. As a result, we believe that almost all renewable fuel produced or imported into the U.S. is assigned RINs under the RFS1 program, and thus the number of RINs available to obligated parties represents as accurately as possible the volume of renewable fuel being used in the U.S. transportation sector.

EISA has dramatically increased the mandated volumes of renewable fuel that obligated parties must ensure are produced and used in the U.S. At the same time, EISA makes it more difficult for renewable fuel producers to demonstrate that they have fuel that qualifies for RIN generation by restricting qualifying renewable fuel to that made from ''renewable biomass,'' defined to include restrictions on the types of land from which feedstocks may be harvested, as discussed in this section. The inclusion of such land restrictions under RFS2 may mean that, in some situations, a renewable fuel producer would prefer to forgo the benefits of RIN generation to avoid the cost and difficulty of ensuring that its feedstocks qualify for RIN generation. If a sufficient number of renewable fuel producers acted in this way, it could lead to a situation in which not all qualifying fuel is assigned RINs, thus resulting in a short RIN market that could force obligated parties into non-compliance. Another possible outcome would be that the demand for and price of RINs would increase significantly, making compliance by obligated parties more costly and difficult than necessary and raising prices for consumers.

In order to avoid situations in which obligated parties cannot comply with

[21] *See http://silvis.forest.wisc.edu/projects/US_WUI_2000.asp.*

their annual RVOs and the volume mandates in EISA are not met, or instances where the requirements are met but at an inflated price, we believe that our proposal should ensure that RINs are generated for all fuel made from feedstock that meets the definition of renewable biomass and which meets the GHG emissions reduction thresholds set out in EISA. This would require eliminating any incentive for renewable fuel producers to avoid ascertaining where their feedstocks come from. As described in Section III.B.4.d below, we propose to require a demonstration of the type of land used to produce any feedstock used in the production of renewable fuel, regardless of whether RINs are generated or not, and to require that RINs be generated for all qualifying fuel.

However, we also seek comment on an alternative approach wherein a renewable fuel producer would not be required to make any demonstration with regard to the origin of feedstocks used in fuel production if the fuel producer were not generating RINs. In this situation, we would rely on the price of RINs in the market to encourage renewable fuel producers to generate RINs where possible. This approach would have the advantage of lessening the regulatory burden for renewable fuel producers using feedstock that is not renewable biomass, and would generally simplify the regulations relating to implementation of the renewable biomass definition. The disadvantage to this approach, as discussed above, would be the increased potential for a RIN shortage caused by renewable fuel producers choosing not to generate RINs for qualifying renewable fuel and a concurrent increase in the price of RINs that do exist. Under such circumstances, it is likely that some obligated parties could not acquire sufficient RINs for compliance purposes, while others could comply but at an inflated cost.

A further step that we could take to streamline not just the implementation of the renewable biomass definition, but also the tracking and trading of RINs, would be to remove the restriction established under the RFS1 rule requiring that RINs be assigned to batches of renewable fuel and transferred with those batches. Instead, renewable fuel producers could sell RINs (with a K code of 2 rather than 1) separately from volumes of renewable fuel. While this alternative approach could potentially place obligated parties at greater risk of market manipulation by renewable fuel producers, it could also provide a greater incentive for producers to demonstrate that the renewable biomass definition has been met for their feedstocks. That is, by having the flexibility to sell RINs independent from volume, producers could potentially command higher prices for those RINs. This would make RINS more valuable to them, and provide an incentive to generate as many RINs as possible. As a result, producers would be motivated to demonstrate that their feedstocks meet the renewable biomass definition. However, this approach could also increase compliance costs for obligated parties. For further discussion of this approach, see Section III.H.4.

c. Review of Existing Programs

i. USDA Programs

To inform our approach for designing an implementation scheme for the renewable biomass land restrictions under RFS2, we reviewed a number of programs and models that track, certify, or verify agricultural and silvicultural products or land use in the U.S. and abroad. First we looked at several existing programs administered by USDA that involve data collection from agricultural land owners, farmers, and forest owners. However, while USDA obtains and maintains valuable data from agricultural land owners, producers, and forest owners for assessing the status of agricultural land, forest land, and other types of land that could be used for renewable fuel feedstock production, Section 1619 of the Food, Conservation, and Energy Act of 2008 (the 2008 Farm Bill) and policies of certain USDA agencies significantly limit EPA's ability to access such data in a timely and meaningful way. Given that agricultural land owners, producers, and forest owners already report a great deal of information to USDA, having access to such information could enable EPA to avoid having to require duplicative reporting or recordkeeping and thereby minimize any burden that RFS2 may place on parties in the renewable fuel feedstock supply chain, from feedstock producer to renewable fuel producer, while still allowing us to ensure that the land restrictions on renewable biomass production are adhered to. We request comment on how EPA could acquire the type of information submitted by parties such as agricultural land owners, producers, and forest owners to USDA agencies in order to aid in administering RFS2. Having access to such information could be valuable to EPA in informing our enforcement actions.

ii. Third-Party Programs

To inform our options for how we might verify and track renewable biomass, we also explored non-governmental, third-party verification programs used for certifying and tracking agricultural and forest products from point of origin to point of use both within the U.S. and outside the U.S. The United Kingdom and the EU are looking to such third-party verification programs to implement the sustainability provisions of their biofuels programs. There is no third-party organization that certifies agricultural land, managed tree plantations, and forests; rather, each generally focuses on one area. Due to this constraint, we examined third party organizations that certify specific types of biomass from croplands and organizations that certify forest lands.

We examined third-party organizations that focus on a particular type of feedstock used for renewable fuel production, including the Roundtable on Sustainable Palm Oil and the Basel Criteria for Responsible Soy Production. These initiatives have outlined traceable certification programs for industry to follow. Two other cooperative organizations whose primary concern is renewable fuel production from biomass are the Roundtable on Sustainable Biofuels (RSB) and the Better Sugarcane Initiative (BSI). At present, the RSB and BSI are still in their developmental stages and do not have fully developed certification processes.

We also examined the work of the international Soy Working Group, comprised of representatives from industry, the Brazilian government, and international non-governmental organizations (NGOs), which recently announced a one-year extension of a moratorium on the use of soy harvested from recently deforested lands in the Brazilian Amazon. This moratorium is the result of a negotiated voluntary agreement through which companies that purchase Brazilian soy work with their suppliers to ensure that they source their soy from farms cultivated prior to August 2006. The Brazilian Association of Vegetable Oil Industries (ABIOVE) and Brazil's National Association of Grain Exporters (ANEC) have used aerial photography to identify whether any newly deforested areas were used to grow soy, and Greenpeace, one of the NGOs involved in the agreement, uses satellite imagery and aerial photography to perform spot checks for enforcement purposes.

Another new example of a renewable fuel feedstock verification system is the

Verified Sustainable Ethanol initiative, which established a series of criteria for ethanol produced in Brazil and sold to Swedish ethanol importer SEKAB. The Brazilian sugarcane ethanol industry trade association, UNICA, its member companies, and SEKAB established the criteria to promote environmental and social sustainability of sugarcane ethanol exported to Sweden. The agreement is between companies, and it relies on a third-party auditor to inspect Brazilian feedstock and ethanol production facilities to verify compliance with the criteria.

We also examined third-party organizations that specialize in certifying sustainable forest lands. The Sustainable Agriculture Network (SAN), through the Rainforest Alliance, provides comprehensive certification of wooded areas used for commercial development through sustainable processes in the United States and Latin American countries. The SAN certifies approximately 10 million acres of land worldwide, with minimal agricultural land certified in the U.S.[22]

We examined the certification process of the Forest Stewardship Council (FSC) because of their international recognition for certifying sustainable forests and their recordkeeping requirement for ''chain of supply'' certification for products. The FSC certifies 22 million acres of land in the U.S. according to certification standards designed for nine separate regions within the U.S., and it provides an example for chain-of-custody and product segregation requirements.[23] Finally, we examined the American Tree Farm program and Sustainable Forestry Initiative (SFI).

The criteria used to certify participants through third-party verification systems are overall more comprehensive and generally more stringent than the land restrictions contained within the definition of renewable biomass. However, three issues emerged through our investigation of these existing third-party verification systems that would make it difficult to adopt or incorporate any one of them into our regulations for the land restriction provisions under EISA. First, as previously noted, many of these third-party certifiers are limited in the scope of products that they certify. Second, the acreage of agricultural land or actively managed tree plantations certified through third parties in the U.S. covers only a small portion of the total available land and forests estimated to qualify for renewable biomass production under the EISA definition. Third, none of the existing third-party systems had definitions or criteria that perfectly matched the land use definitions and restrictions contained in the EISA definition of renewable biomass. Thus, we have determined that at this time we cannot rely on any existing third-party verification program solely to implement the land restrictions on renewable biomass under RFS2. We believe there is potential benefit in utilizing third-party verification programs if these issues can be addressed, and in the following section we offer one possible scenario as an implementation alternative. Nonetheless, we seek comment on our conclusion that there are currently no appropriate third-party verification systems for renewable biomass that could be adopted under RFS2. We further seek comment on whether any existing program or combination of programs would be able to meet the definitions and adopt the land restriction criteria proposed for RFS2 to assist industry in meeting their obligations under this proposed program.

d. Approaches for Domestic Renewable Fuel

Consistent with RFS1, renewable fuel producers would be responsible for generating RINs under RFS2. In order to make a determination whether or not their fuel is eligible for RINs, renewable fuel producers would need to have at least basic information about the origin of their feedstock. The following approaches for implementing the land restrictions on renewable biomass contained in EISA illustrate the variety of ways that renewable fuel feedstocks could be handled under RFS2. These options are presented singly, but we seek comment on how they might be combined to create the most appropriate, practical, and enforceable implementation scheme for renewable biomass under RFS2.

One approach for ensuring that producers generate RINs properly would be for EPA to require that renewable fuel producers obtain documentation about their feedstocks from their feedstock supplier(s) and take the measures necessary to ensure that they know the source of their feedstocks and can demonstrate to EPA that they have complied with the EISA definition of renewable biomass. Under this approach, EPA would require renewable fuel producers who generate RINs to certify on their renewable fuel production reports that the feedstock used for each renewable fuel batch meets the definition of renewable biomass. We would require renewable fuel producers to maintain sufficient records to support these claims. Specifically, renewable fuel producers who use planted crops or crop residue from existing agricultural land, or who use planted trees or slash from actively managed tree plantations, would be required to have copies of their feedstock producers' written records that serve as evidence of land being actively managed (or fallow, in the case of agricultural land) since December 2007, such as sales records for planted crops or trees, livestock, crop residue, or slash; a written management plan for agricultural or silvicultural purposes; or, documentation of participation in an agricultural or silvicultural program sponsored by a Federal, state or local government agency. In the case of all other biomass, we would require renewable fuel producers to have, at a minimum, written certification from their feedstock supplier that the feedstock qualifies as renewable biomass. We seek comment on whether we should also require renewable fuel producers that use slash and pre-commercial thinnings from non-federal forestland and biomass from areas at risk of wildfire to maintain additional records to support the claim that these feedstocks meet the definition of renewable biomass. These records could include sworn statements from licensed or registered foresters, contracts for tree or slash removal or documentation of participation in a fire mitigation program. We seek comment on other methods of verifying renewable fuel producers' claims that feedstocks qualify for these categories of renewable biomass. A review of such records would become part of the producer's annual attest engagement, the annual audit of their records by an independent third party (*see* Section IV.A for a full discussion of attest engagement requirements).

A renewable fuel producer would only be permitted to produce and sell renewable fuel without RINs if he demonstrates that the feedstocks used to produce his fuel do not meet the definition of renewable biomass. This approach would ensure that renewable fuel producers could not avoid the generation of RINs simply by failing to make a demonstration regarding the land used to produce their feedstocks. Thus, renewable fuel producers would be required to keep records of their feedstock source(s), regardless of

[22] Forest acreage taken from USDA Economic Research Service, *Major uses of Land in the United States, 2002,* Economic Information Bulletin No. (EIB–14), May 2006.

[23] FSC certified acreage taken from FSC–US, *Prospectus,* 2005.

whether RINs were generated or not. At a minimum, renewable fuel producers who do not generate RINs would need to have certification from their feedstock supplier that their feedstock does not meet the definition of renewable biomass. In the event that some portion of a load of feedstock does meet the definition of renewable biomass and some portion does not, the renewable fuel producer would need to maintain documentation from their supplier that states the percentage of each portion. All of these records would be included as part of the renewable fuel producer's annual attest engagement. The renewable fuel producer would also indicate on his renewable fuel production report that he did not generate RINs for fuel made from feedstock that did not meet the definition of renewable biomass.

Some stakeholders have expressed concern about EPA specifying the records that a renewable fuel producer must obtain from their feedstock supplier. We therefore seek comment on an approach that would require renewable fuel producers to certify on their renewable fuel production reports that their feedstock either met or did not meet the definition of renewable biomass and would require producers to maintain sufficient records to support their claims, but would stop short of specifying what those records would have to include. We anticipate that a large portion of feedstocks that qualify as renewable biomass will be obtained from existing agricultural land or actively managed tree plantations, for which, by definition, documentation already exists. We believe that, in most other cases, feedstock producers will have or will be able to create other forms of documentation that could be provided to renewable fuel producers in order to provide adequate assurance that the feedstock in question meets the definition of renewable biomass. As described above, there are many existing programs, such as those administered by USDA and independent third-party certifiers, that could be useful to verify that feedstock from certain land qualifies as renewable biomass.

We anticipate that these self-certification approaches would result in renewable fuel producers amending their contracts and altering their supply chain interactions to satisfy their need for documented assurance and proof about their feedstock's origins. Enforcement under either of these approaches would rely in part on EPA's review of renewable fuel production reports and attest engagements of renewable fuel producers' records. EPA would also consult other data sources, including any data made available by USDA, and could conduct site visits or inspections of feedstock producers' and suppliers' facilities. We seek comment on the feasibility and practical limitations of EPA working with publicly available USDA data to keep track of significant land use changes in the U.S. and around the world and to note general increases in feedstock supplier productivity that might signal cultivation of new agricultural land for renewable fuel feedstock production.

Either of these approaches would easily fold into existing and newly proposed registration, recordkeeping, reporting, and attest engagement procedures. They would also place the burden of implementation and enforcement on renewable fuel producers rather than bringing feedstock producers and suppliers directly under EPA regulation. In this way, they would minimize the number of regulated parties under RFS2. They would also allow, to varying degree, the renewable fuel industry to determine the most efficient means of verifying and tracking feedstocks from the point of production to the point of consumption, thereby minimizing any additional cost and administrative burden created by the EISA definition of renewable biomass.

Another alternative would be for EPA to establish a chain-of-custody tracking system from feedstock producer to renewable fuel producer through which renewable fuel producers would obtain information regarding the lands where their feedstocks were produced. This information would accompany each transfer of custody of the feedstock until the feedstock reaches the renewable fuel producer. Renewable fuel feedstock producers, suppliers and handlers would not have any reporting obligations. EPA would, however, require all feedstock producers, suppliers, and handlers to maintain as records these chain-of-custody documents for all biomass intended to be used as a renewable fuel feedstock. Renewable fuel producers would also be required to maintain these chain-of-custody tracking documents in their records and would have to include them as part of their records presented during their annual attest engagement.

An additional alternative would be for EPA to require renewable fuel producers to set up and administer a quality assurance program that would create an additional level of rigor in the implementation scheme for the EISA land restrictions on renewable biomass. The quality assurance program could include (1) an unannounced independent third party inspection of the renewable feedstock producer's facility at least once per quarter or once every 15 deliveries, whichever is more frequent, (2) an unannounced independent third party inspection of each intermediary facility that stores renewable fuel feedstock received by the renewable fuel producer at least once per quarter, and (3) on each occasion when the independent third party inspection reveals noncompliance, the renewable fuel producer must (a) conduct an investigation to determine the proper number of RINs that should have been generated for a volume of fuel and either generate or retire an equal number of RINs, depending on whether the fuel's feedstock did or did not meet the definition of renewable biomass, (b) conduct a root cause analysis of the violation, and (c) refuse to accept or process feedstock from the renewable fuel feedstock producer unless or until the feedstock producer takes appropriate corrective action to prevent future violations.

This alternative could provide a partial affirmative defense either for renewable producers that illegally generate RINs for fuel made from feedstocks that do not qualify as renewable biomass or for renewable fuel producers who do not generate enough RINs for fuel made from feedstocks that do qualify as renewable biomass. In either case, the producers must demonstrate that the violation was caused by a feedstock producer or supplier and not themselves; that the commercial documents (e.g., bills of lading) received with the feedstock indicated that the feedstock either met (in the case that RINs were generated illegally) or did not meet (in the case that an inadequate number of RINs were generated) the land restrictions for renewable biomass, and that they met EPA's quality assurance program requirements. A renewable fuel producer that generates RINs for fuel made from a feedstock that does not meet the definition of renewable biomass, but that qualifies for the partial affirmative defense, would still have to retire a number of RINs equal to the illegally generated RINs. Likewise, a renewable fuel producer that does not generate sufficient RINs for fuel made from a feedstock that does meet the definition of renewable biomass, but that qualifies for the partial affirmative defense, would have to generate enough RINs to make up the difference. However, in neither case would they be subject to civil penalties.

As yet another alternative approach, EPA could bring together renewable fuel producers and renewable fuel feedstock producers and suppliers to develop an industry-wide quality assurance program for the renewable fuel production supply chain, following the model of the successful Reformulated Gasoline Survey Association. We believe that this alternative could be less costly than if each individual renewable fuel producer were to create their own quality assurance program, and it would add a quality assurance element to RFS2 while creating the possibility for a partial affirmative defense for renewable fuel producers and feedstock producers and suppliers.

The program would be carried out by an independent surveyor funded by industry and consist of a nationwide verification program for renewable fuel producers and renewable feedstock producers and handlers designed to provide independent oversight of the feedstock designations and handling processes that are required to determine if a feedstock meets the definition of renewable biomass. Under this alternative, a renewable fuel producer and its renewable feedstock suppliers and handlers would have to participate in the funding of an organization which arranges to have an independent surveyor conduct a program of compliance surveys. Compliance surveys would be carried out by an independent surveyor pursuant to a detailed survey plan submitted to EPA for approval by November 1 of the year preceding the year in which the alternative quality assurance sampling and testing program would be implemented. The survey plan would include a methodology for determining when the survey samples would be collected, the locations of the surveys, the number of inspections to be included in the survey, and any other elements that EPA determines are necessary to achieve the same level of quality assurance as the requirement included in the RFS2 regulations at the time.

Under this alternative, the independent surveyor would be required to visit renewable feedstock producers and suppliers to determine if they are properly designating their product and adhering to adequate chain of custody requirements. This nationwide sampling program would be designed to ensure even coverage of renewable feedstock producers and suppliers. The surveyor would generate and report the results of the surveys to EPA each calendar quarter. In addition, where the survey finds improper designations or handling, the liable parties would be responsible for identifying and addressing the root cause of the violation to prevent future violations. When a violation is detected, the renewable fuel producer that participates in the consortium would be deemed to have met the quality assurance criteria for a partial affirmative defense. If the renewable fuel producer met the other applicable criteria, he would have to take corrective action to retire or generate the appropriate number of RINs depending on the violation, but he would not be subject to civil penalties.

Some stakeholders have suggested that EPA take advantage of existing satellite and aerial imagery and mapping software and tools to implement the renewable biomass provisions of EISA. One way to do so would be for EPA to develop a renewable fuel mapping Web site to assist regulated parties in meeting their obligation to identify the location of land where renewable fuel feedstocks are produced. Such a Web site could include an interactive map that would allow renewable feedstock producers to trace the boundaries of their property and create an electronic file with information regarding the land where their renewable fuel feedstocks were produced, such as a code that identifies the plot of land. This would allow the feedstock producer to provide information, such as a standard land ID code, on all bills of lading or other commercial documents that identify the type and quantity of feedstock being delivered to the renewable fuel producer. Renewable fuel producers could then make a determination regarding whether or not the renewable fuel feedstock that they use meets the definition of renewable biomass, and is therefore eligible or not for RIN generation.

Feedstock producers would not necessarily be required to use this Internet-based tool to identify the location where renewable fuel feedstocks are produced, since many feedstock producers already participate in various government or insurance programs that have required them to map the location of their fields. But the map would enable renewable fuel producers to verify the accuracy of these descriptions and report these locations to EPA using the interactive mapping tool on EPA's Web site. EPA specifically solicits comment on the practicability of constructing an accurate map from existing data sources.

As noted above, EPA recognizes that land restrictions contained within the definition of renewable biomass may not, in practice, result in a significant change in agricultural practices. EPA also recognizes that the implementation options described in this proposal could impose costs and constraints on existing storage, transportation, and delivery systems for feedstocks, in particular for corn and soybeans in the U.S. We therefore seek comment on a stakeholder suggestion to establish a baseline level of production of biomass feedstocks such that reporting and recordkeeping requirements would be triggered only when the baseline production levels of feedstocks used for biofuels were exceeded. Such an approach would avoid imposing a new recordkeeping burden on the industry as long as biofuels demand is met with existing feedstock production. We seek comment on this alternative, including how to set the baseline production levels and information on appropriate data sources in the U.S. and in other countries that produce feedstocks that could be used for renewable fuel production, and on how to track whether the feedstock use for biofuels production has exceeded baseline production levels. We also solicit comment on whether this approach could be applied to all types of feedstocks on which EISA places land restrictions, or if it would only be appropriate for traditional agricultural crops such as corn, soybeans, and sugarcane for which historical acreage data exists both domestically and internationally.

EPA acknowledges that under this alternative, while there could be a net increase in lands being cultivated for a particular crop, we would presume that increases in cultivation would be used to meet non-biofuels related feedstock demand. We also acknowledge that such an approach would be difficult to enforce because data that could indicate that baseline production levels were exceeded in a given year would likely be delayed by many months, such that the recordkeeping requirements for renewable fuel producers would also be delayed. During the interim period, renewable fuel producers would have generated RINs for fuel that did not qualify for credit under the program, and any remedial steps to invalidate such RINs after the fact could be costly and burdensome to all parties in the supply chain. Nonetheless, we seek comment on the approach as described above.

We seek comment on all of these approaches and what combination of these approaches would be the most appropriate, enforceable, and practical for ensuring that the land restrictions on renewable biomass contained in EISA are implemented under RFS2. We also seek comment on whether there are other possible approaches that would be superior to those we have described above. We also note that we intend to monitor RIN generation and the trends in renewable fuel feedstock sources as RFS2 implementation gets underway, and that we may make changes to the approach we adopt in the final RFS2 regulations if renewable fuel feedstock production conditions change or if new, better renewable biomass verification tools become available.

e. Approaches for Foreign Renewable Fuel

EISA creates unique challenges related to the implementation and enforcement of the definition of renewable biomass for foreign-produced renewable fuel. In order to address these issues, we propose to require foreign producers of renewable fuel who export to the U.S. to meet the same compliance obligations as domestic renewable fuel producers. These obligations would include facility registration and submittal of independent engineering reviews (described in Section III.C below), and reporting, recordkeeping, and attest engagement requirements. They would also include the same obligations that domestic producers have for verifying that their feedstock meets the definition of renewable biomass as described above, such as certifying on each renewable fuel production report that their renewable fuel feedstock meets the definition of renewable biomass and working with their feedstock supplier(s) to ensure that they receive and maintain accurate and sufficient documentation in their records to support their claims. As under the RFS1 program for producers of cellulosic fuel, the foreign producer would be required to comply with additional requirements designed to ensure that enforcement of the regulations at the foreign production facility would not be compromised. For instance, foreign producers would be required to designate renewable fuel intended for export to the U.S. as such and segregate the volume until it reaches the U.S. and post a bond to ensure that penalties can be assessed in the event of a violation. Moreover, as a regulated party under the RFS2 program, foreign producers would have to allow for potential visits by EPA enforcement personnel to review the completeness and accuracy of records and registration information.

We propose that a foreign renewable fuel producer, like a domestic renewable fuel producer, could only produce and sell renewable fuel for export to the U.S. without RINs if he demonstrated that the land used to produce his feedstocks did not meet the definition of renewable biomass. This approach would ensure that foreign renewable fuel producers could not avoid the generation of RINs for fuel shipped to the U.S. simply by failing to make any demonstration regarding the land used to produce their feedstocks. Thus, foreign renewable fuel producers that export their product to the U.S. would be required to keep records of the type of land used to produce their feedstock regardless of whether RINs are generated or not. Section III.D.2.b outlines more specifically our proposed requirements for foreign renewable fuel producers.

Importers will likely have less knowledge than a foreign renewable fuel producer would about the point of origin of their fuel's feedstock and whether it meets the definition of renewable biomass. Therefore, we are proposing that in the event that a batch of foreign-produced renewable fuel does not have RINs accompanying it, an importer must obtain documentation from its producer that states whether or not the definition of renewable biomass was met by the fuel's feedstock. With such documentation, the importer would be required to generate RINs (if the definition of renewable biomass is met) or would be prohibited from doing so (if the definition is not met) prior to introducing the fuel into commerce in the U.S. Without such documentation, the fuel would not be permitted for importation. Section III.D.2.c outlines our proposed requirements for importers more fully.

We seek comment on whether and to what extent the approaches for ensuring compliance with the EISA's land restrictions by foreign renewable fuel producers could or should differ from the proposed approach for domestic renewable fuel producers. In light of the challenges associated with enforcing the EISA's land restrictions in foreign countries, we believe that it may be appropriate to require foreign renewable fuel producers to use an alternative method of demonstrating compliance with these requirements. We seek comment on whether foreign renewable producers exporting product to the U.S. should have to comply with any of the alternatives described for domestic renewable fuel producers under this section. For example, we seek comment on whether a foreign renewable fuel producer should have to demonstrate that it had a contract in place with its renewable feedstock producer that required designation and chain of custody and handling methods similar to one of the alternatives for domestic renewable fuel producers discussed above. We also seek comment on whether foreign renewable fuel producers that export product to the U.S. should have to provide EPA with the location of land from which they will or have acquired feedstocks, along with historical satellite or aerial imagery demonstrating that feedstocks from these lands meet the definition of renewable biomass. We seek comment on whether foreign renewable fuel producers should also be subject to the same quality assurance requirements relating to their feedstock sources as domestic renewable fuel producers, and whether they should have the same option to use an approved survey consortium in lieu of implementing their own individual quality assurance programs.

We also seek comment on an alternative that would provide foreign renewable fuel producers an option of participating in RFS2 (in a manner consistent with our main proposal), or not participating at all. If they elected not to participate in RFS2, they could export renewable fuel to the United States without RINs, and without providing any documentation as to whether or not the fuel was made with renewable biomass. However, they would also have to meet requirements for segregating their fuel from renewable fuel for which RINs were generated, and the importer of their fuel would be required to track it to ensure that the fuel remains segregated in the U.S. and is not used by a domestic company for illegal RIN generation. This alternative would provide foreign renewable fuel producers an option not available to domestic renewable fuel producers, who in all cases would be required to document whether or not their feedstock met the definition of renewable biomass, and who would be required to generate RINs for their product if it was. As discussed in Section III.B.4.b.ii of this preamble, EPA believes that in order for obligated parties to meet the increasing annual volume requirements under RFS2, all qualifying renewable fuel will need to have RINs generated for it. Nonetheless, this alternative recognizes the potential difficulty of applying renewable biomass verification procedures in the international context, and provides an exemption process that EPA expects would only be used by relatively small producers for whom the burden of participating in the RFS2 program would outweigh the benefits, and whose total production volume would be negligible.

C. Expanded Registration Process for Producers and Importers

In order to implement and enforce the new restrictions on qualifying renewable fuel under RFS2, we are proposing that the registration process for renewable fuel producers and importers be revised. Under the existing RFS1 program, all producers and importers of renewable fuel who produce or import more than 10,000 gallons of fuel annually must register with EPA's fuels program prior to generating RINs. Renewable fuel producer and importer registration under the existing RFS program consists of filling out two forms: 3520–20A (Fuels Programs Company/Entity Registration), which requires basic contact information for the company and basic business activity information (e.g., for an ethanol producer, they need to indicate that they are a RIN generator), and 3520–20B (Gasoline Programs Facility Registration) or 3520–20B1 (Diesel Programs Facility Registration), which requires basic contact information for each facility owned by the producer or importer. More detailed information on the renewable fuel production facility, such as production capacity and process, feedstocks, and products is not required for most producers or importers to generate RINs under RFS1 (producers of cellulosic biomass ethanol and waste-derived ethanol are the exception to this).

Due to the revised definitions of renewable fuel under EISA, as well as other changes, we believe it necessary to expand the registration process for renewable fuel producers and importers in order to implement the new program effectively. Specifically, generating and assigning a certain category of RIN to a volume of fuel is dependent on whether the feedstock used to produce the fuel meets the definition of renewable biomass, whether the lifecycle greenhouse gas emissions of the fuel meets a certain GHG reduction threshold and, in some cases, whether the renewable fuel production facility is considered to be grandfathered into the program. Unless we require producers, including foreign producers, and importers to provide us with information on their feedstocks, facilities, and products, we cannot adequately implement or enforce the program or have confidence that producers and importers are properly categorizing their fuel and generating RINs. In particular, our proposed approach for ensuring that the GHG emission reduction thresholds for each category of renewable fuel are met will require producers and importers to determine the proper category assignment for their fuel based on a combination of their feedstock, production processes, and products (see Section III.D.2 for the proposed list). Such information, therefore, is central to program implementation. Therefore, we are proposing new registration requirements for all domestic renewable fuel producers, importers, and foreign renewable fuel producers. We also plan on integrating registration procedures with the new EPA Moderated Transaction System, discussed in detail in Section IV.E of this preamble. We encourage those affected by the proposed registration requirements to review the document entitled ''Proposed Information Collection Request (ICR) for the Renewable Fuels Standard (RFS2) Program—EPA ICR 2333.01,'' and an Addendum to the proposed ICR, which have been placed in the public docket and to provide comments to us regarding the burdens associated with the proposed registration requirements.

1. Domestic Renewable Fuel Producers

The most significant proposed changes to the current registration system pertain to the information that a producer will need to provide EPA prior to generating RINs. As noted above, we are proposing that producers provide information about their products, feedstocks, and facilities in order to be registered for the RFS2 program. Information contained in a producer's registration would be used to verify the validity of RINs generated and their proper categorization as either cellulosic biofuel, biomass-based diesel, advanced biofuel, or other renewable fuel.

With respect to products, we are interested in the types of renewable fuel and co-products that a facility is capable of producing. With respect to feedstocks, we believe it is necessary to have on file a list of all the different feedstocks that a renewable fuel producer's facility is capable of converting into renewable fuel. For example, if a renewable fuel producer produces fuel from both cellulosic material, such as corn stover, and non-cellulosic material, such as corn starch, the producer may be eligible to generate RINs in two different categories (cellulosic biofuel and renewable fuel). This producer's registration information would be required to list both of these feedstocks before we would allow two different categories of RINs to be generated.

With respect to the producer's facilities, we are proposing two types of information that would need to be reported to the Agency. First, we believe it is important to have information on file that describes each facility's fuel production processes (e.g., wet mill, dry mill, thermochemical, etc.), and thermal/process energy source(s). Second, in order to determine what production volumes would be grandfathered and thus deemed to be in compliance with the 20% GHG threshold, we would require evidence and certification of the facility's qualification under the definition of ''commence construction'' as well as information necessary to establish it's renewable fuel baseline volume per the proposal outlined in Section III.B.3 of this preamble.

Under the existing RFS1 program, producers of cellulosic biomass and waste-derived ethanol are required to have an annual engineering review of their production records performed by an independent third party who is licensed Professional Engineer (P.E.) who works in the chemical engineering field. This independent third party need not be based in the United States, but must hold a P.E. Each review must be kept on file by both the producer and the engineer for five years. The independent third party must include documentation of its qualifications as part of the engineering review. Foreign producers of cellulosic biomass and waste-derived ethanol are also required to have an engineering review of their facilities, with a report submitted to EPA that describes in detail the physical plant and its operation. These requirements helps ensure that producers who claim to be producing such fuel, which earns 2.5 RINs per gallon rather than 1.0 RIN per gallon for corn-based ethanol under RFS1, are in fact doing so.

We believe that the requirement for an on-site engineering review is an effective implementation tool and propose to adopt the requirement under RFS2, with the following changes. First, we propose expanding the applicability of the requirement to all renewable fuel producers due to the variability of production facilities, the increase in the number of categories of renewable fuels, and the importance of generating RINs in the correct category. Second, we propose that every renewable fuel producer must have the on-site engineering review of their facility performed in conjunction with his or her initial registration for the new RFS program in order to establish the proper basis for RIN generation, and every three years thereafter to verify that the fuel pathways established in their initial registration are still applicable. These requirements would apply unless the renewable fuel producer updates its facility registration information to qualify for a new RIN category (i.e., D code), in which case the review would need to be performed within 60 days of the registration update. Finally, we propose that producers be required to submit a copy of their independent engineering review to EPA rather than simply maintaining it in their records. We believe that this extra step is necessary for verification and enforcement purposes.

In addition to the new registration requirements for all renewable fuel producers who produce greater than 10,000 gallons of product each year, we seek comment on whether to require renewable fuel producers and importers in the U.S. who produce or import less than 10,000 gallons per year to register basic information about their company and facility (or facilities) with EPA, similar to information currently required of renewable fuel producers under RFS1. This information would complement information submitted to EPA under the Fuels and Fuel Additives Registration System (FFARS) program to help ensure that EPA has a complete record of renewable fuel production and importation in the U.S.

2. Foreign Renewable Fuel Producers

Under the current RFS program, foreign renewable fuel producers of cellulosic biomass ethanol and waste-derived ethanol may apply to EPA to generate RINs for their own fuel. This allows a foreign producer of this renewable fuel to obtain the same benefits of higher credit value as domestic producers of this category of renewable fuel. Under the RFS1 regulations, the foreign fuel producer must meet a variety of requirements established to make the program effective and enforceable with respect to a foreign producer. These requirements mirror a number of similar fuel provisions that apply to foreign refiners in other fuels programs. For RFS2, we propose that foreign producers of renewable fuel must meet the same requirements as domestic producers, including registering information about their feedstocks, facilities, and products, as well as submitting an on-site independent engineering review of their facilities at the time of registration for the program and every three years thereafter. These requirements would apply to all foreign renewable fuel producers who export their products to the U.S., whether or not they qualify to generate RINs for their fuel. They would also be subject to the variety of enforcement related provisions that apply under RFS1 to foreign producers of cellulosic biomass or waste derived ethanol.

As discussed in Section III.C.1, the existing RFS1 program requires that the independent engineering review be conducted by an independent third party who is a licensed P.E. who works in the chemical engineering field. This P.E. need not be based in the United States. The independent third party must include documentation of its qualifications as part of the engineering review.

Since implementation of RFS1 we have received questions about engineers who are licensed by other countries that may have equivalent licensing requirements to those associated with the P.E. designation in the United States. The existing RFS1 program does not permit independent third party review by a party who is not a licensed P.E. We invite comment on whether or not we should permit independent third parties who are based in—and licensed by—foreign countries and who work in the chemical engineering field to demonstrate the foreign equivalency of a P.E. license.

We also seek comment on requiring foreign renewable fuel producers to provide EPA with the location of land from which they will acquire feedstocks, along with historical satellite or aerial imagery demonstrating that the lands from which they acquire feedstock are eligible under the definition of renewable biomass (*see* Section III.B.4 for a full discussion of our proposed and alternative approaches for foreign renewable fuel producers to verify their feedstocks meet the definition of ''renewable biomass'').

3. Renewable Fuel Importers

A renewable fuel importer is required under RFS1 to register basic information about their company with EPA prior to generating RINs. Under the proposed new RFS2 program, we are proposing that only in limited cases can importers generate RINs for imported fuel that they receive without RINs. In any case, whether they receive fuel with or without RINs, an importer must rely on his supplier, a foreign renewable fuel producer, to provide documentation to support any claims for their decision to generate or not to generate RINs. An importer may have an agreement with a foreign renewable fuel producer for the importer to generate RINs if the foreign producer has not done so already. However, the foreign renewable fuel producer must be registered with EPA as noted above. Section III.D.2.c describes our proposed RIN generating restrictions and requirements for importers under RFS2.

4. Process and Timing

We intend to make forms for expanded registration for renewable fuel producers and importers available electronically, with paper registration only in exceptional cases. We propose that registration forms will have to be submitted by January 1, 2010 (the proposed effective date of the final RFS2 regulations), or 60 days prior to a producer producing or importer importing any renewable fuel, whichever dates comes later. If a producer changes to a feedstock that is not listed in his registration information on file with EPA but the feedstock will not incur a change of RIN category for the fuel (i.e., a change in the appropriate D code), then we propose that the producer must update his registration information within seven (7) days of the change. However, if a producer's feedstock, facility (including industrial processes or thermal energy source), or products undergo changes that would qualify his renewable fuel for a new RIN category (and thus a new D code), then we propose that such an update would need to be submitted at least 60 days prior to the change, followed by submittal of a complete on-site independent engineering review of the producer's facility also within 60 days of the change.

D. Generation of RINs

Under RFS2, each RIN would continue to be generated by the producer or importer of the renewable fuel, as in the RFS1 program. In order to determine the number of RINs that must be generated and assigned to a batch of renewable fuel, the actual volume of the batch of renewable fuel must be multiplied by the appropriate Equivalence Value. The producer or importer must also determine the appropriate D code to assign to the RIN to identify which of the four standards the RIN can be used to meet. This section describes these two aspects of the generation of RINs. We propose that other aspects of the generation of RINs, such as the definition of a batch and temperature standardization, as well as the assignment of RINs to batches, should remain unchanged from the RFS1 requirements.

1. Equivalence Values

For RFS1, we interpreted CAA section 211(o) as allowing us to develop Equivalence Values representing the number of gallons that can be claimed for compliance purposes for every physical gallon of renewable fuel. We described how the use of Equivalence Values adjusted for renewable content and based on energy content in comparison to the energy content of ethanol was consistent with Congressional intent to treat different renewable fuels differently in different circumstances, and to provide incentives for use of renewable fuels in certain circumstances, as evidenced by the specific circumstances addressed by Congress. This included the direction that EPA establish ''appropriate'' credit values in certain circumstances, as well as provisions in the statute providing for different credit values to be assigned to the same volume of different types of renewable fuels (e.g., cellulosic and waste-derived fuels). We also noted that the use of Equivalence Values based on energy content was an appropriate measure of the extent to which a renewable fuel would replace or reduce the quantity of petroleum or other fossil fuel present in a fuel mixture. The result was an Equivalence Value for ethanol of 1.0, for butanol of 1.3, for biodiesel (mono alkyl ester) of 1.5, and for non-ester renewable diesel of 1.7. EPA stated that these provisions indicated that Congress did not intend to limit the RFS program solely to a straight volume measurement of gallons. EPA also noted that the use of Equivalence Values would not interfere with meeting the overall volume goals specified by Congress, given the various provisions that make achievement of the specified volumes imprecise. *See* 72 FR 23918–23920, and 71 FR 55570–55571.

EISA has not changed certain of the statutory provisions we looked to for support under RFS1 in establishing Equivalence Values based on relative volumetric energy content in comparison to ethanol. For instance, CAA 211(o) continues to give EPA the authority to determine an ''appropriate'' credit for biodiesel, and also directs EPA to determine the ''appropriate'' amount of credit for renewable fuel use in excess of the required volumes.

However, EISA made a number of other changes to CAA section 211(o) that impact our consideration of Equivalence Values in the context of the RFS2 program. For instance, EISA eliminated the 2.5-to-1 credit for cellulosic biomass ethanol and waste-derived ethanol and replaced this provision with large mandated volumes of cellulosic biofuel and advanced biofuels. Under the RFS1 program, an Equivalence Value of 2.5 applies to these types of ethanol through the end of 2012. Under the new RFS2 program, these types of ethanol would have an Equivalence Value of 1.0, consistent with all other forms of ethanol.

EISA also expanded the program to include four separate categories of renewable fuel (cellulosic biofuel, biomass-based diesel, advanced biofuel, and total renewable fuel) and included GHG thresholds in the definitions of each category. Each of these categories of renewable fuel has its own volume requirement, and thus there will exist a guaranteed market for each. As a result there may no longer be a need for additional incentives for certain fuels in the form of Equivalence Values greater than 1.0. In addition, the use of an energy-based approach to Equivalence Values raises some questions, discussed below, concerning the impact of such Equivalence Values on the biomass-based diesel volume requirement and in the initial years on the advanced biofuel volume requirement. Overall EPA believes that the statute continues to be ambiguous on this issue, and we are therefore co-proposing and seeking comment on two options for Equivalence Values:

1. Equivalence Values would be based on the energy content and renewable content of each renewable fuel in comparison to denatured ethanol, consistent with the approach under RFS1.

2. All liquid renewable fuels would be counted strictly on the basis of their measured volumes, and the Equivalence Values for all renewable fuels would be 1.0 (essentially, Equivalence Values would no longer apply).

While these two different approaches to volume would have an impact on the market values of renewable fuels with different energy contents as explained more fully below, the overall impact on the program would likely be small since we are projecting that the overwhelming majority of renewable fuels will be ethanol (*see* further discussion in Section V.A.2).

Under either option, non-liquid renewable fuels such as biogas and renewable electricity would continue to be valued based on the energy contained in one gallon of denatured ethanol. In the RFS1 final rulemaking, we specified that 77,550 Btu of biogas be counted as the equivalent of 1 gallon of renewable fuel with an assigned Equivalence Value of 1.0. We propose to maintain this approach to non-liquid renewable fuels under the RFS2 program under either approach to Equivalence Values, but with a small modification to make the ethanol energy content more accurate. The energy content of denatured ethanol was specified as 77,550 Btu/gal under RFS1, but a more accurate value would be 77,930 Btu/gal. Thus we propose to use 77,930 Btu to convert biogas and renewable electricity into volumes of renewable fuel under RFS2.

Under the second option in which all liquid renewable fuels would be counted strictly on the basis of their measured volumes, we would need to determine how to treat the small amount of denaturant in ethanol and the nonrenewable portion of biodiesel. Under RFS1, Equivalence Values were determined from a formula that included measures of both volumetric energy content and renewable content. The renewable content was intended to take into account the portion, if any, of a renewable fuel that originated from a fossil fuel feedstock. EISA eliminated the statutory language on which the inclusion of renewable content was based, and instead restricts renewable fuels that are valid under the RFS2 program to those produced from renewable biomass. In the case of fuels produced from both renewable and nonrenewable feedstocks, we have interpreted this to mean only that portion of the volume attributable to the renewable feedstocks (*see* further discussion in Section III.D.4 below). However, we do not believe that this approach is appropriate for the denaturant in ethanol and the small amount of non-renewable methanol used in the production of biodiesel, since Congress clearly intended that ethanol and biodiesel be included as a renewable fuel, and they are only used as a fuel under these circumstances. We therefore propose to treat the denaturant in ethanol and the nonrenewable portion of biodiesel as de minimus and thus count them as part of the renewable fuel volume under an approach to Equivalence Values in which all liquid renewable fuels would be counted strictly on the basis of their measured volumes. As a result, under this co-proposed approach we are proposing that the full formula used to calculate Equivalence Values under RFS1 be eliminated from the regulations and that the Equivalence Value for all renewable fuels be specified as 1.0. Nevertheless, we seek comment on this approach.

Although there are several reasons for a straight volume approach as discussed above, there are also several reasons to maintain the ethanol-equivalent energy content approach to Equivalence Values of RFS1. For instance, in our discussions with stakeholders, some have argued that the existence of four standards is not a sufficient reason to eliminate the use of energy-based Equivalence Values for RFS2. The four categories are defined in such a way that a variety of different types of renewable fuel could qualify for each category, such that no single specific type of renewable fuel will have a guaranteed market. For example, the cellulosic biofuel requirement could be met with both cellulosic ethanol or cellulosic diesel. As a result, the existence of four standards under RFS2 may not obviate the value of standardizing for energy content, which provides a level playing field under RFS1 for various types of renewable fuels based on energy content.

More importantly, they argue that a straight volume approach would be likely to create a disincentive for the development of new renewable fuels that have a higher energy content than ethanol in the same way as the current ethanol tax credit structure. For a given mass of feedstock, the volume of renewable fuel that can be produced is roughly inversely proportional to its energy content. For instance, one ton of biomass could be gasified and converted to syngas, which could then be catalytically reformed into either 90 gallons of ethanol (and other alcohols) or 50 gallons of diesel fuel (and naphtha).[24] If RINs were assigned on a straight volume basis, the producer could maximize the number of RINs he is able to generate and sell by producing ethanol instead of diesel. Thus, even if the market would otherwise lean towards demanding greater volumes of diesel, the greater RIN value for producing ethanol may favor its production instead. However, if the energy-based Equivalence Values were maintained, the producer could assign 1.7 RINs to each gallon of diesel made from biomass in comparison to 1.0 RIN to each gallon of ethanol from biomass, and the total number of RINs generated would be essentially the same for the diesel as it would be for the ethanol. The use of energy-based Equivalence Values could thus provide a level playing field in terms of the RFS program's incentives to produce different types of renewable fuel from the available feedstocks. The market would then be free to choose the most appropriate renewable fuels without any bias imposed by the RFS regulations, and the costs imposed on different types of renewable fuel through the assignment of RINs would be more evenly aligned with the ability of those fuels to power vehicles and engines, and displace fossil fuel-based gasoline or diesel.

Moreover, the technologies for producing more energy-dense fuels such as cellulosic diesel are still in the early stages of development and may benefit from not having to overcome the disincentive in the form of the same Equivalence Value based on straight volume. Given the projected tightness in the distillate market and relative excess supply in the gasoline market in the coming years, allowing the market to choose freely may be important to overall fuel supply. In the extreme, the cellulosic biofuel standard could then be met by roughly 10 billion gallons of a cellulosic diesel fuel instead of the 16 billion gallons of cellulosic ethanol assumed for the impacts analysis of this proposal. The same amount of petroleum energy would be displaced, but by different physical volumes.

As discussed above, there are no provisions in EISA that explicitly instruct the Agency to change from the approach to Equivalence Values adopted in RFS1. However, there is a question of how to address the biomass-based diesel requirement under such an approach. In that context, it does appear that Congress intended the required volumes of biomass-based diesel to be treated as diesel volumes rather than ethanol-equivalent volumes. Therefore EPA proposes that, for the biomass-based diesel volume mandate under an ethanol-equivalent energy content approach to Equivalence Values, the compliance calculations would be structured such that this requirement is treated in effect as a straight volume-based requirement.[25]

In addition, it is also clear that Congress established the advanced biofuel standard in EISA to begin to take affect in 2009. However, if we maintain the ethanol-equivalent energy content approach for RFS2, and biodiesel continues to have an Equivalence Value of 1.5, then from 2009–2012 the combination of the biomass-based diesel standard and the cellulosic biofuel standard will meet or exceed the advanced biofuel standard. Unless we were to waive a portion of either the biomass-based diesel standard or the cellulosic biofuel standard, the advanced biofuel standard would not have an independent effect until 2013. While EPA recognizes this, EPA believes that the long term benefits of an energy based Equivalence Value may be significantly greater than any temporary diminishment in the real world impact of the advanced biofuel mandate.

In recognition of the competing perspectives, we request comment on both co-proposed approaches to the Equivalence Values: (1) Retaining the energy-based approach of the RFS1 program, and (2) a straight volume approach measured in liquid gallons of renewable fuel.

2. Fuel Pathways and Assignment of D Codes

As described in Section III.A, we propose that RINs under RFS2 would continue to have the same number of digits and code definitions as under RFS1. The one change would be that, while the D code would continue to identify the standard to which the RIN could be applied, it would be modified to have four values corresponding to the four different renewable fuel categories defined in EISA. These four D code values and the corresponding categories are shown in Table III.A–1.

In order to generate RINs for renewable fuel that meets the various eligibility requirements (*see* Section III.B), a producer or importer must know which D code to assign to those RINs. We propose that a producer or importer would determine the appropriate D code using a lookup table in the regulations. The lookup table would list various combinations of fuel type, production process, and feedstock, and the producer or importer would choose the appropriate combination representing the fuel he is producing and for which he is generating RINs. Parties generating RINs would be required to use the D code specified in the lookup table and would not be permitted to use a D code representing a broader renewable fuel category. For example, a party whose fuel qualified as biomass-based diesel could not choose to categorize that fuel as advanced biofuel or general renewable fuel.

This section describes our proposed approach to the assignment of D codes to RINs for domestic producers, foreign producers, and importers of renewable fuel. Subsequent sections address the generation of RINs in special circumstances, such as when a production facility has multiple applicable combinations of feedstock, fuel type, and production process within a calendar year, production facilities that co-process renewable biomass and fossil fuels, and production

[24] Another example would be a fermentation process in which one ton of cellulose could be used to produce either 70 gallons of ethanol or 55 gallons of butanol.

[25] The proposed regulations and the ensuing discussion in Sections III and IV of this proposal reflect straight volume approach, however, the impacts analysis of the program are calculated using volumes based on ethanol-equivalent energy content. Were we to maintain the energy content approach to Equivalence Values, then we believe the biomass-based diesel standard should be treated in effect as a biodiesel volume, reflecting the nature of this standard, while the other three standards would be treated as ethanol-equivalent volumes. In order to effectuate this, we are considering two approaches. Under either approach all RINs would be generated based on ethanol-equivalent volume, including biomass-based diesel RINs. Under one approach, we would propose that the biomass-based diesel standard also be expressed as an ethanol-equivalent volume (e.g., 1.5 billion ethanol-equivalent gallons in 2012). Another approach would be to have the standard expressed as a volume of biomass-based diesel, and to require the biomass-based diesel RINs be adjusted back to a volume basis, with this adjustment just for purposes of the biomass-based diesel standard but not for purposes of the other fuels mandates. Either approach would have the same result.

facilities for which the lookup table does not provide an applicable D code.

a. Domestic Producers

For domestic producers, the lookup table would identify individual fuel ''pathways'' comprised of unique combinations of the type of renewable fuel being produced, the feedstock used to produce the renewable fuel, and a description of the production process. Each pathway would be assigned to one of the four specific D codes on the basis of the revised renewable fuel definitions provided in EISA and our assessment of the GHG lifecycle performance for that pathway. A description of the lifecycle assessment of each fuel pathway and the process we used for determining the associated D code can be found in Section VI. Note that the subsequent generation of RINs would also require as a prerequisite that the feedstocks used to make the renewable fuel meet the definition of ''renewable biomass'' as described in Section III.B.4, including applicable land use restrictions. Moreover, a domestic producer could not introduce renewable fuel into commerce without generating RINs unless he had records demonstrating that the feedstocks used to produce the fuel did not meet the definition of renewable biomass. *See* Section III.B.4.b.ii for further discussion of this issue.

Through our assessment of the lifecycle GHG impacts of different pathways and the application of the EISA definitions for each of the four categories of renewable fuel, including the GHG thresholds, we have determined that all four categories would have pathways that could be used to meet the Act's volume requirements. For example, ethanol made from corn stover or switchgrass in an enzymatic hydrolysis process would count as cellulosic biofuel. Biodiesel made from waste grease could count as biomass-based diesel. Ethanol made from sugarcane sugar may count as advanced biofuel depending on the results of the lifecycle assessment conducted for the final rule and a determination about whether the GHG threshold for advanced biofuel should be adjusted downward. Finally, under an assumed 100-year timeframe and 2% discount rate for GHG emissions impacts, a variety of pathways would count as generic renewable fuel under the RFS2 program, including ethanol made from corn starch in a facility powered by biomass combustion and biodiesel made from soybean oil. The complete list of pathways that would be valid under our proposed RFS program is provided in the regulations at § 80.1426(d), based upon an assumed 100-year timeframe and 2% discount rate for GHG emission impacts.

Domestic producers would choose the appropriate D code from the lookup table in the regulations based on the fuel pathway that describes their facility. The fuel pathway must be specified by the producer in the registration process as described in Section III.C. If there were changes to a domestic producer's facility or feedstock such that their fuel would require a D code that was different from any D code(s) which their existing registration information already allowed, the producer would be required to revise its registration information with EPA 30 days prior to changing the applicable D code it uses to generate RINs. Situations in which multiple fuel pathways could apply to a single facility are addressed in Section III.D.3 below.

For producers for whom none of the defined fuel pathways in the lookup table would apply, we propose two possible treatments. First, such producers may be able to generate RINs through our proposed system of default D codes as described in Section III.D.5 below. Second, if a producer meets the criteria for grandfathered status as described in Section III.B.3 and his fuel meets the definition of renewable fuel as described in Section III.B.1, he could continue to generate RINs for his fuel but would use a D code of 4 for those RINs generated under the grandfathering provisions. If a producer was not covered by either of these two treatments, we propose that he would not be permitted to generate RINs for his product until the lookup table in the regulations was modified to include a pathway applicable to his operations.

A diesel fuel product produced from cellulosic feedstocks that meets the 60% GHG threshold could qualify as either cellulosic biofuel or biomass-based diesel. As a result, we are proposing that the producer of such ''cellulosic diesel'' be given the choice of whether to categorize his product as either cellulosic biofuel or biomass-based diesel. This would allow the producer to market his product and the associated RINs on the basis of market demand. However, we request comment on an alternative approach as shown in Table III.D.2.a–1 in which an additional D code would be defined to represent cellulosic diesel and an obligated party would be given the choice of using cellulosic diesel RINs either to meet his or her RVO for cellulosic biofuel or for biomass-based diesel.

TABLE III.D.2.a–1—ALTERNATIVE D CODE DEFINITIONS TO ACCOMMODATE CELLULOSIC DIESEL

D value	Meaning under RFS1	Meaning under RFS2
1	Cellulosic biomass ethanol	Cellulosic biofuel.
2	Any renewable fuel that is not cellulosic biomass ethanol.	Biomass-based diesel.
3	Not applicable	Cellulosic biofuel or biomass-based diesel.
4	Not applicable	Advanced biofuel.
5	Not applicable	Renewable fuel.

Under this alternative, producers of cellulosic diesel would assign a D code of 3 to their product rather than being given a choice of whether to assign a D code of 1 or 2. Any obligated party that acquired a RIN with a D code of 3 could apply that RIN to either its cellulosic biofuel or biomass-based diesel obligation, but not both. The advantage of this alternative approach is that it reflects the full compliance value for the product, and hence its potential value to an obligated party. The obligated party is then given the ability to make a choice about how to treat cellulosic diesel based on the market price and availability of RINs with D codes of 1 and 2. We request comment on this alternative approach to the designation of D codes for cellulosic diesel.

b. Foreign Producers

Under RFS1, foreign producers have the option of generating RINs for the renewable fuel that they export to the U.S. if they want to designate their fuel as cellulosic biomass ethanol or waste-derived ethanol, and thereby take advantage of the additional 1.5 credit value afforded by the 2.5 Equivalence Value for such products. In order to ensure that EPA has the ability to enforce the regulations relating to the generation of RINs from such foreign ethanol producers, the RFS1 regulations require them to post a bond and submit to third-party engineering reviews of their production process. If a foreign producer does not generate RINs for the renewable fuel that it exports to the U.S., the U.S. importer is responsible for generating the RINs associated with the imported renewable fuel.

EISA creates unique challenges in the implementation and enforcement of the renewable fuel standards for imported renewable fuel. Unlike our other fuels programs, EPA cannot determine whether a particular shipment of renewable fuel is eligible to generate RINs under the new program by testing the fuel itself. Instead, information regarding the feedstock that was used to produce renewable fuel and the process by which it was produced is vital to determining the proper renewable fuel category and RIN type for the imported fuel. It is for these reasons that we required foreign producers of cellulosic biomass ethanol or waste-derived ethanol under RFS1 to take additional steps to ensure the validity of the RINs they generate.

For RFS2 we are proposing a similar approach to that taken under RFS1, but with a number of modifications to account for the changes that EISA makes to the definition of renewable fuel. Thus, we propose that foreign producers would have the option of generating RINs for any renewable fuel (not just the cellulosic biofuel category) that they export to the U.S. If the foreign producer did not generate RINs, the importer would be required to generate RINs for the imported renewable fuel. Our proposed importer provisions are covered in more detail in Section III.D.2.c below.

In general, we propose that foreign producers of renewable fuel who intend to export their fuel to the U.S. would use the same process as domestic producers to generate RINs, namely the lookup table to identify the appropriate D code as a function of fuel type, production process, and feedstock. They would be required to be registered with the EPA as a producer under the RFS2 program and would be subject to the same recordkeeping, reporting, and attest engagement requirements as domestic producers, including those provisions associated with ensuring that the feedstocks they use meet the definition of renewable biomass. They would also be required to submit to third-party engineering reviews of their production process and use of feedstocks, just as domestic producers are. As under the RFS1 program, the foreign producer would also be required to comply with additional requirements designed to ensure that enforcement of the regulations at the foreign production facility would not be compromised. For instance, foreign producers would be required to designate renewable fuel intended for export to the U.S. as such and segregate the volume until it reaches the U.S. in order to ensure that RINs are only generated for volumes imported into the U.S. Foreign producers would also be required to post a bond to ensure that penalties can be assessed in the event of a violation. Moreover, as a regulated party under the RFS2 program, foreign producers must allow for potential visits by EPA enforcement personnel to review the completeness and accuracy of records and registration information. Non-compliance with any of these requirements could be grounds for refusing to allow renewable fuel from such a foreign producer to be imported into the U.S.

For RFS2, we are proposing a number of additional provisions to address foreign companies that produce renewable fuel for export to the United States, but that do not generate their own RINs for that renewable fuel. These provisions are intended to account for the greater difficulties in verifying the validity of RINs for imported renewable fuel when the importer is generating the RINs, given that the importer would generally not have direct knowledge of the feedstocks used to produce the renewable fuel, the land used to grow those feedstocks, or the fuel production process. We believe that these additional provisions would be necessary to ensure that RINs representing imported renewable fuel and used by obligated parties have been generated appropriately.

As described more fully in Section III.D.2.c below, importers would only be allowed to import renewable fuel from registered foreign producers and would be required to generate RINs for all imported renewable fuel that has not been assigned RINs by the foreign producer. Like domestic and foreign producers who generate RINs, the importer must be able to determine if the renewable biomass definition has been met before generating RINs. The importer must also have enough information about the production process and feedstock to be able to use the lookup table to identify the appropriate D code to include in the RINs he generates. Since the foreign producer is the only party who can provide this information, we believe that it would be appropriate to require the foreign producer of any renewable fuel exported to the U.S. to provide this information to the U.S. importer before the renewable fuel enters U.S. commerce even if the foreign producer is not generating RINs himself. Moreover, the foreign producer should be liable for the accuracy of this information just as if he were the party generating RINs. Therefore, in order to ensure that RINs are valid regardless of who generates them, we propose that all the provisions described above that would be applicable to a foreign producer who generates RINs would also apply to a foreign producer who does not generate RINs but still exports renewable fuel to the U.S. This would include registration with the EPA under the RFS2 program, being subject to all the recordkeeping, reporting, and attest engagement requirements, and posting a bond. The only exception would be that the foreign producer would not be required to segregate a specific volume between the foreign producer's facility and the import facility if the foreign producer is not generating RINs, since the importer would be the primary party responsible for measuring the volume before generating RINs.

Although we are proposing that RINs for imported renewable fuel could be generated by either the importer or the foreign producer, it is possible that this could result in difficulty in verifying that only one set of RINs has been generated for a given volume of renewable fuel. One possible solution would be to require a foreign producer to make a decision regarding RIN generation that would apply for an entire calendar year. Under this approach, a foreign producer would be required to either generate RINs for all the renewable fuel that he exports to the U.S within a calendar year, or to generate no RINs for the renewable fuel that he exports to the U.S within a calendar year. While we are not proposing this approach it today's action, we request comment on it.

As described in Section III.B.4.b.ii, we are proposing that domestic producers could only introduce renewable fuel into commerce without generating RINs if they demonstrate that feedstocks used to produce the fuel did not meet the definition of renewable biomass. Thus it would not be sufficient for a domestic producer to simply fail to make a demonstration that the renewable biomass definition had been met, and thereby avoid generation of RINs. We propose that a similar approach would be applied to imported renewable fuel. As a result, all renewable fuel that would be imported into the U.S. would be required to come with documentation regarding the status of the feedstock's compliance with the renewable biomass definition. In the case of documentation indicating that the renewable biomass definition had been met, the importer would be required to generate RINs. In the case of documentation indicating that the renewable biomass definition had not been met, the importer would be prohibited from generating RINs but could still import the renewable fuel into the U.S. Renewable fuel that was not accompanied by any documentation regarding the status of the feedstock's compliance with the renewable biomass definition could not be imported into the U.S.

Our proposed approach to foreign producers is consistent with the approach we propose taking for domestic producers, in that the producer is responsible for ensuring that RINs generated for renewable fuel used in the U.S. are valid and categorized appropriately. While our proposed approach to foreign producers of renewable fuel under RFS2 would require additional actions in comparison to their general requirements under RFS1, we believe these provisions would be necessary to ensure that the volume mandates shown in Table II.A.1–1 are met, given the new definitions for renewable fuel and renewable biomass in EISA. We request comment on our proposed approach to foreign producers.

c. Importers

Under RFS1, importers who import more than 10,000 gallons in a calendar year must generate RINs for all imported renewable fuel based on its type, except for cases in which the foreign producer generated RINs for cellulosic biomass ethanol or waste-derived ethanol. Due to the new definitions of renewable fuel and renewable biomass in EISA, importers could no longer generate RINs under RFS2 on the basis of fuel type alone. Instead, they must be able to determine whether or not the renewable biomass definition has been met for the renewable fuel they intend to import, and they must also have sufficient information about the feedstock and process used to make the renewable fuel to allow them to identify the appropriate D code from the lookup table for use in the RINs they generate. As described in Section III.D.2.b above, we are proposing that in order for an importer to import renewable fuel into the U.S., the foreign producer would have to provide this information to the importer.

Under today's proposal, importers would be able to import renewable fuels only under one of the following scenarios:

1. The importer receives RINs generated by the registered foreign producer when he imports a volume of renewable fuel.

2. The imported renewable fuel is not accompanied by RINs generated by the registered foreign producer, and the foreign producer provides the importer with:

—A demonstration that the renewable biomass definition has been met for the volume of renewable fuel being imported.

—Information about the feedstock and production process used to produce the renewable fuel.

In this case, the importer would be required to generate RINs for the imported renewable fuel before introducing it into commerce in the contiguous 48 states or Hawaii.

3. The imported renewable fuel is not accompanied by RINs generated by the registered foreign producer, and the foreign producer provides the importer with a demonstration that the renewable biomass definition has not been met for the volume of renewable fuel being imported. See further discussion of this issue in Section III.B.4.b.ii. The importer would be prohibited from generating RINs for the imported volume, but could still introduce the renewable fuel into commerce.

If none of these scenarios applied, the importer would be prohibited from importing renewable fuel. Our proposed approach to imported fuels would apply to both neat renewable fuel and renewable fuels blended into gasoline or diesel.

As described in Section III.B.4.e, we also seek comment on an alternative approach to imported renewable fuel in which foreign renewable fuel producers would have the option of not participating in RFS2 but still export renewable fuel to the U.S. Under this alternative approach, foreign producers would have to meet requirements for segregating their fuel from renewable fuel for which RINs were generated, and the importer of their fuel would be required to track it to ensure that the fuel remains segregated in the U.S. and is not used by a domestic company for illegal RIN generation.

While it is important that all RINs be based on accurate information about the feedstocks and production process used to produce the renewable fuel, it may not be necessary to place the burden upon importers for acquiring this information before they generate RINs. Instead, an alternative approach would prohibit importers from generating any RINs, and instead require foreign producers to generate RINs for all renewable fuel that they export to the U.S. We recognize that this would be a significant change from RFS1, and thus we are not proposing it. However, since it would place the same responsibilities on foreign producers as domestic producers, we request comment on it.

3. Facilities With Multiple Applicable Pathways

If a given facility's operations can be fully represented by a single pathway, then a single D code taken from the lookup table will be applicable to all RINs generated at or imported into that facility. However, we recognize that this will not always be the case. Some facilities use multiple feedstocks at the same time, or switch between different feedstocks over the course of a year. A facility may be modified to produce the same fuel but with a different process, or may be modified to produce a different type of fuel. Any of these situations could result in multiple pathways being applicable to a facility, and thus there may be more than one D code used for various RINs generated at the facility.

If more than one pathway applies to a facility within a compliance period, no special steps would need to be taken if the D codes were the same for all the applicable pathways. In this case, all RINs generated at the facility would have the same D code. As for all other producers, the producer with multiple applicable pathways would describe its feedstock(s), fuel type(s), and production process(es) in its annual report to the Agency so that we could verify that the D code used was appropriate.

However, if more than one pathway applies to a facility within a compliance period and these pathways have been assigned different D codes, then the producer must determine which D codes to use when generating RINs. There are a number of different ways that this could occur, and our proposed approach to designating D codes for RINs in these cases is described in Table III.D.3–1.

TABLE III.D.3–1—PROPOSED APPROACH TO ASSIGNING MULTIPLE D CODES FOR MULTIPLE APPLICABLE PATHWAYS

Case	Description	Proposed approach
1	The pathway applicable to a facility changes on a specific date, such that one single pathway applies before the date and another single pathway applies on and after the date.	The applicable D code used in generating RINs must change on the date that the fuel produced changes pathways.
2	One facility produces two or more different types of renewable fuel at the same time.	The volumes of the different types of renewable fuel should be measured separately, with different D codes applied to the separate volumes.
3	One facility uses two or more different feedstocks at the same time to produce a single type of renewable fuel.	For any given batch of renewable fuel, the producer should assign the applicable D codes using a ratio (explained below) defined by the amount of each type of feedstock used.

In general, we are not aware of a scenario in which a facility uses two different processes in parallel to convert a single type of feedstock into a single type of renewable fuel. Therefore, we have not created a case in Table III.D.3–1 to address it. However, we know that some corn-ethanol facilities may dry only a portion of their distiller's grains and leave the remainder wet. Using the lifecycle with an assumed 100 year timeframe and 2% discount rate for GHG emission impacts, the treatment of the distiller's grains could impact the determination of whether the 20% GHG threshold for renewable fuel has been met, a corn-ethanol facility that dries some portion of its distiller's grains would need to implement additional technologies in order to qualify to generate RINs for all the ethanol it produces (if the facility has not been grandfathered). The lifecycle analyses conducted for this proposal only examined cases in which a corn-ethanol facility dried 100% of its distiller's grains or left 100% of its distiller's grains wet. As a result, a corn-ethanol facility that dried only a portion of its distiller's grain would be treated as if it dried 100% of its grains, and would thus need to implement additional GHG-reducing technologies as described in the lookup table in order to qualify to generate RINs. This is reflected in the list of required production technologies in the lookup table at § 80.1426(d) for facilities that dry any portion of their distiller's grains. In practice, depending on the selection of other technologies, it may be possible for a facility using some combination of dry and wet distiller's grains to meet the 20% GHG threshold. Therefore we request comment on whether a selection of pathways should be included in the lookup table that represent corn-ethanol facilities that dry only a portion of their distiller's grains. We also request comment on whether RINs could be assigned to only a portion of the facility's ethanol in cases wherein only a portion of the distiller's grains are dried.

We propose that the cases listed in Table III.D.3–1 be treated as hierarchical, with Case 2 only being used to address a facility's circumstances if Case 1 is not applicable, and Case 3 only being used to address a facility's circumstances if Case 2 is not applicable. We believe that this approach covers all likely cases in which multiple applicable pathways may apply to a renewable fuel producer. Some examples in which Case 2 or 3 would apply are provided in Table III.D.3–2.

TABLE III.D.3–2—EXAMPLES OF FACILITIES WITH MULTIPLE PATHWAYS

Example	Applicable case	Reasoning
Facility makes both diesel and naphtha (a gasoline blendstock) from gasified biomass in a Fischer-Tropsch process.	2	The production of two types of renewable fuel from the same feedstock and process makes it highly likely that the two pathways would be assigned the same D code. If LCA determined that this was not the case, the volumes of diesel and naphtha can be measured separately and assigned separate batch-RINs with different D codes.
Facility produces ethanol from corn starch and corn cobs/husks	3	There is only one fuel produced, so Case 2 cannot apply.
Facility makes both ethanol and butanol through two different processes using corn starch.	2	Case 2 is the default since there are two separate fuels produced. However, Case 3 would not apply regardless because there is only one feedstock.
Facility makes ethanol through an enzymatic hydrolysis process using both switchgrass and corn stover.	3	There is only one fuel produced, so Case 2 cannot apply.

A facility where two or more different types of feedstock were used to produce a single fuel (such as Case 3 in Table III.D.3–1) would be required to generate two or more separate batch-RINs [26] for a single volume of renewable fuel, and these separate batch-RINs would have different D codes. The D codes would be chosen on the basis of the different pathways as defined in the lookup table in § 80.1426(d). The number of gallon-RINs that would be included in each of the batch-RINs would depend on the relative amount of the different types of feedstocks used by the facility. We propose to use the useable energy content of the feedstocks to determine how many gallon-RINs should be assigned to each D code. Our proposed calculations are given in the regulations at § 80.1126(d)(5).

In determining the useable energy content of the feedstocks, we propose to take into account several elements to ensure that the number of gallon-RINs associated with each D code is appropriate. For instance, we propose

[26] Batch-RINs and gallon-RINs are defined in the RFS1 regulations at 40 CFR 80.1101(o).

that only that portion of a feedstock which is expected to be converted into renewable fuel by the facility should be counted in the calculation. For example, a biochemical cellulosic ethanol conversion process that could not convert the lignin into ethanol would not include the lignin portion of the biomass in the calculation. This approach would also take into account the conversion efficiency of the facility. We propose that the producer of the renewable fuel would be required to designate this fraction for the feedstocks processed by his facility and to include this information as part of its reporting requirements.

We are also proposing to use the energy content of the feedstocks instead of their mass since we believe that their relative energy contents are more closely related than their mass to the energy in the renewable fuel. Producers would be required to designate the energy content (in Btu/lb) of the portion of each of their feedstocks which is converted into fuel. We request comment on whether producers would determine these values independently for their own feedstocks, or whether a standard set of such values should be developed and incorporated into the regulations for use by all renewable fuel producers. If we did specify a standard set of energy content values, we request comment on what those values should be and/or the most appropriate sources for determining those values.

Some components in the calculation of the useable energy content of feedstocks are unlikely to vary significantly for a particular type of feedstock. This would include that portion of a feedstock which is expected to be converted into renewable fuel by the facility, and the relative amount of energy in the two feedstocks. For these factors, we propose that one set of values be determined by the producer and applied to all renewable fuel production within a calendar year. The values could be reassessed annually and adjusted as necessary.

Although we are proposing annual determinations of the portion of a feedstock which is expected to be converted into renewable fuel by the facility and the relative amount of energy in the two feedstocks, we are proposing daily determinations of the total mass of each type of feedstocks used by the facility. This approach would take into account the fact that the relative amount of the different feedstocks used could vary frequently, and thus the determination of the total useable energy content of the feedstocks would be unique to the renewable fuel produced each day. We believe that renewable fuel producers would have ready access to information about total feedstock mass used each day, such that the timely generation of RINs should not be unduly affected. We request comment on the effort and time involved in collecting information on feedstock mass and translating this information on a daily basis into RINs assigned to volumes of renewable fuel.

In order to generate RINs when the processing of two or more different feedstocks in the same facility results in two or more different applicable D codes but a single renewable fuel, the producer would continue to determine the total number of gallon-RINs that must be generated for and assigned to a given volume of renewable fuel using the process established under RFS1. In short, the total volume of the renewable fuel would be multiplied by its Equivalence Value. However, the feedstock's useable energy content would be used to divide the resulting number of gallon-RINs into two or more groups, each corresponding to a different D code. Two, three, or more separate batch-RINs could then be generated and assigned to the single volume of renewable fuel. The sum of all gallon-RINs from the different batch-RINs would be equal to the total number of gallon-RINs that must be generated to represent the volume of renewable fuel.

As described in Section III.J, we propose that in their reports, producers of renewable fuel be required to submit information on the feedstocks they used, their production processes, and the type of fuel(s) they produced during the compliance period. This would apply to both domestic producers and foreign producers who export any renewable fuel to the U.S. We would use this information to verify that the D codes used in generating RINs were appropriate.

4. Facilities That Co-Process Renewable Biomass and Fossil Fuels

We expect situations to arise in which a producer uses a renewable feedstock simultaneously with a fossil fuel feedstock, producing a single fuel that is only partially renewable. For instance, biomass might be cofired with coal in a coal-to-liquids (CTL) process that uses Fischer-Tropsch chemistry to make diesel fuel, biomass and waste plastics might be fed simultaneously into a catalytic or gasification process to make diesel fuel, or vegetable oils could be fed to a hydrotreater along with petroleum to produce a diesel fuel. In these cases, the diesel fuel would be only partially renewable. We propose that RINs must be generated in such cases, but in such a way that the number of gallon-RINs corresponds only to the renewable portion of the fuel.

Under RFS1, we created a provision to address the co-processing of ''renewable crudes'' along with petroleum feedstocks to produce a gasoline or diesel fuel that is partially renewable. *See* 40 CFR 80.1126(d)(6). However, this provision would not apply in cases where either the renewable feedstock or the fossil fuel feedstock is a gas (e.g., biogas, natural gas) or a solid (e.g. biomass, coal). Therefore, we propose to eliminate the existing provision applicable only to liquid feedstocks and replace it with a more comprehensive approach that could apply to liquid, solid, or gaseous feedstocks and any type of conversion process. Our proposed approach would be similar to the treatment of renewable fuels with multiple D codes as described in Section III.D.3 above. Thus, the producer would determine the renewable fuel volume that would be assigned RINs based on the amount of energy in the renewable feedstock relative to the amount of energy in the fossil feedstock. Just as two different batch-RINs would be generated for a single volume of renewable fuel produced from two different renewable feedstocks, only one batch-RIN would be generated for a single volume of renewable fuel produced from both a renewable feedstock and a fossil feedstock, and this one batch-RIN would be based on the contribution that the renewable feedstock makes to the volume of renewable fuel. See § 80.1426(d)(6) for our proposed calculations under these circumstances.

For facilities that co-process renewable biomass and fossil fuels to produce a single fuel that is partially renewable, we propose to use the relative energy in the feedstocks to determine the number of gallon-RINs that should be generated. As shown in the regulations at § 80.1426(d)(6), the calculation of the relative energy contents would include factors that take into account the conversion efficiency of the plant, and as a result, potentially different reaction rates and byproduct formation for the various feedstocks would be accounted for. The relative energy content of the feedstocks would be used to adjust the basic calculation of the number of gallon-RINs downward from that calculated on the basis of fuel volume alone. The D code that would be assigned to the RINs would be drawn from the lookup table in the regulations as if the feedstock was entirely renewable biomass. Thus, for instance, a coal-to-liquids plant that co-processes some cellulosic biomass to make diesel fuel would be treated as a plant that produces only cellulosic diesel for purposes of identifying the appropriate D code.

One drawback of our proposed approach is that it does nothing to address lifecycle GHG emissions associated with the portion of the fuel that comes from the fossil fuel feedstock. While the lifecycle GHG thresholds under RFS2 are specific to fuels made from renewable biomass, allowing a fuel producer to generate RINs for the co-processing of renewable biomass with fossil fuels might provide a greater incentive for production of transportation fuels from processes that have high lifecycle GHGs. In such cases, the GHG benefits of the renewable fuel may be overwhelmed by the GHG increases of the fossil fuel. This is of particular concern for CTL processes which generally produce higher lifecycle GHG emissions per unit of transportation fuel produced than traditional refinery processes that use petroleum. Under our proposed approach to the treatment of co-processing of renewable biomass and fossil fuels, incentives would be provided for renewable fuels with lower lifecycle GHG emissions, but there will be little disincentive for production of high GHG-emitting fuels made from fossil fuels.

As an alternative to our proposed approach, we could treat fuels produced through co-processing of renewable biomass and fossil fuel feedstocks in an aggregate fashion rather than focusing only on the renewable portion of those fuels. In this approach, we would require the whole fuel produced at co-processing facilities to meet the lifecycle GHG thresholds under RFS2. If, for instance, a diesel fuel produced from co-processing renewable biomass and coal in a Fischer-Tropsch process were determined to not meet the 20% GHG threshold, no RINs could be generated even though the renewable portion of the diesel fuel might meet the 20% GHG threshold. However, this alternative approach would require a lifecycle analysis that is specific to the relative amounts of renewable biomass and fossil fuel feedstock being used at a particular facility, which would in turn require a facility-specific lifecycle GHG model. As described in Section II.A.3, this is beyond the capabilities of our current modeling tools. Moreover, this alternative approach could have undesirable effects on facilities that produce renewable fuel from multiple renewable feedstocks. For instance, if a facility produced ethanol from both corn starch and corn stover and the lifecycle GHG assessment was conducted for this specific facility as a whole, it might not meet the 60% GHG threshold for cellulosic biofuel. As a result, the portion of the ethanol produced from corn stover could not be counted as cellulosic biofuel but would instead count only as renewable fuel, even though our lifecycle analyses have determined that ethanol from corn stover does meet the 60% GHG threshold. Nevertheless, we seek comment on this alternative approach.

As another alternative to using the relative energy in the feedstocks to determine the number of gallon-RINs that should be generated, we could allow renewable fuel producers to use an accepted test method to directly measure the fraction of the fuel which originates with biomass rather than a fossil fuel feedstock. For instance, ASTM test method D–6866 can be used to determine the renewable content of gasoline. However, such a test method could not distinguish between fuel made from feedstocks that meet the definition of renewable biomass, and other biomass feedstocks which do not meet the definition of renewable biomass. We request comment on the use of ASTM D–6866 or equivalent test methods to determine the number of RINs generated when multiple feedstocks are used simultaneously to make a fuel.

5. Treatment of Fuels Without an Applicable D Code

Among all fuels covered by our proposed RFS2 program, we have identified a number of specific "pathways" of fuels, defined by fuel type, feedstock, and various production process characteristics. This list includes fuels that either already exist in the marketplace or are expected to exist sometime during the next decade, and for which we had sufficient information to conduct a lifecycle analysis of the GHG emissions. As described in III.D.2, we have assigned each pathway a D code corresponding to the four categories of renewable fuel defined in EISA.

Despite our efforts to explicitly address the existing or possible pathways in our proposed program, it is expected that a fuel, process, or feedstock will arise that is a renewable fuel meeting the RFS definitions, and yet is not among the fuels we explicitly identified in the regulations as a RIN-generating fuel. This could occur for an entirely new fuel type, a known fuel produced from a new feedstock, or a known fuel produced through a unique production process. In such cases, the fuel may meet our definition of renewable fuel covered under our program, but would not have been assigned the appropriate D code in the regulations. To address some of these fuel pathways, we are proposing the use of default D codes.[27]

Under our proposed approach, the producer would be required to register under the RFS program and provide information about their facility as described in Section III.C. The producer will also be required to provide any information necessary for EPA to perform a proper lifecycle analysis. Additionally, the company would need to register their renewable fuel under title 40 CFR part 79 as a motor vehicle fuel. If EPA determines, based on the company's registration, that they are not producing renewable fuel, the company will not be able to generate RINs.

In order to generate RINs, the producer of renewable fuel would apply through our registration system to use the D code that best represents his combination of fuel type, feedstock, and production process. If the producer's combination of fuel type and feedstock, but not production process, is represented in an already defined pathway combination of fuels, processes, or feedstocks, the producer would use the highest numerical D code applicable to the fuel and feedstock combination. For example, if a fuel and feedstock spans the D Codes 3 and 4 then the producer would use 4 until the regulations were updated. The producer then would generate RINs using the D code 4, until EPA could perform a lifecycle analysis and issue a change to the regulations to reflect the new pathway. If the producer is making a new fuel or using a new feedstock that producer will still need to apply, but would be unable to generate RINs until the regulations were updated with the new pathway.

Since certain combinations of fuel, production process, and feedstock have been determined through our lifecycle analysis to not meet the minimum 20% GHG threshold, they would be ineligible to generate RINs and EPA would not allow producers using those processes to generate RINs using a default D code. To effectuate this, we propose to provide a statement in the regulations of pathways that are prohibited from using a default D code. For example, if a producer is producing ethanol from cornstarch in a process that uses coal or natural gas for process heat, then regardless of other elements of the production process the producer may not use a default D code, but must register and provide information

[27] Additional default requirements applicable to importers of renewable fuels are discussed in Section III.D.2.c.

necessary to conduct a lifecycle analysis.

EPA will not conduct a rulemaking every year to adjust the regulations for new fuels, processes, or feedstocks. EPA will periodically update the regulations as necessary under CAA section 211(o)(4) and may take the opportunity to update the list of fuel pathways. Companies are encouraged to work with EPA early to provide information about fuels, processes, or feedstocks not in the regulations so that we can do a proper lifecycle analysis before these fuels, processes, or feedstocks are commercially viable. EPA is proposing that if the regulations are not updated with in 5 years of receipt of the application and the application is not rejected in that time then the producer will no longer be able to generate RINs using a default D code until the regulations are updated.

6. Carbon Capture and Storage (CCS)

One element of the production process that may enable renewable fuel producers to greatly improve their GHG emissions is carbon capture and storage (CCS). CCS involves the process of capturing CO_2 from an industrial or energy-related source, transporting it to a suitable storage site, and isolating it from the atmosphere for long periods of time. While we are not proposing a specific pathway in today's NPRM that would allow a renewable fuel producer to use CCS to demonstrate compliance with the GHG thresholds, we believe that CCS could be an effective method for significantly reducing the GHG emissions associated with renewable fuel production.

Although there are several possible approaches for long-term storage of CO_2, this section will only address geologic storage as a means to reduce CO_2 emissions from renewable fuel production facilities. This method entails injecting CO_2 deep underground and monitoring to ensure long-term isolation from the atmosphere. The remainder of this section describes the efforts to establish regulatory requirements for CCS, and the further work that needs to be done before allowing the use of CCS as an element in pathways eligible for generating RINs under the RFS2 program.

Although there is limited experience with integrated CCS systems in the US, where CO_2 is captured, transported and injected for long-term storage, there are commercial CCS projects operating today and several DOE pilot projects underway to further demonstrate CCS in a variety of industrial sectors and geological settings. The EPA has been working closely with DOE to collectively ensure that governmental research programs address the range of potential environmental risks associated with CCS and that appropriate regulatory frameworks are in place to manage risks.[28]

The EPA has experience regulating underground injection of various fluids and believes that well selected, designed, and managed sites can sequester CO_2 for long periods of time. The Safe Drinking Water Act's (SDWA) Underground Injection Control (UIC) Program has been successfully regulating tens of thousands of injection wells for over 35 years. The UIC program's siting, well construction, and monitoring and testing requirements are keys to ensuring that injected fluids remain in the geologic rock formations specifically targeted for injection.

In March 2007, the EPA issued UIC permitting guidelines for pilot geologic sequestration projects in order to ensure that these projects could move forward under an appropriate regulatory framework. Subsequently, on July 25, 2008, EPA issued a proposed rulemaking that would address commercial-scale projects and establish the regulatory requirements for underground injection of CO_2 for the purpose of geologic storage (73 FR 43492). These proposed regulations include permitting requirements, criteria for establishing and maintaining the mechanical integrity of wells, minimum criteria for siting, injection well construction and operating requirements, recordkeeping and reporting requirements, etc. While these regulations cover many operational aspects of underground injection and monitoring geologic sequestration sites, their purpose is to protect underground sources of drinking water. The SDWA does not provide authority to develop regulations for all areas related to CCS, including capture and transport of CO_2 and accounting or certification for GHG emissions reductions. The UIC requirements will not replace or supersede other statutory or regulatory requirements for protection of human health and the environment. Thus, parties that implemented CCS would still need to obtain all necessary permits from appropriate State and Federal authorities under the Clean Air Act or any other applicable statutes and regulations.

Specific areas that would need to be addressed before allowing the renewable fuel producers to benefit from CCS in meeting GHG thresholds include: the means through which the CO_2 would be captured from the renewable fuel production facility, the minimum fraction that must be captured, appropriate means for transporting to the injection site, and appropriate monitoring procedures to ensure long-term storage of CO_2. We believe the CO_2 that would be most readily available for capture in an ethanol production facility would be that which is produced during the fermentation process, not CO_2 that is generated during the combustion of fossil fuels for process energy, since CO_2 from the fermentation process provides a more concentrated stream that is more amenable to capture. However, we request comment on the efficacy of capturing CO_2 from the combustion of fossil fuels for process heat.

A mechanism for accounting for potential leakage of captured CO_2 during transport to the storage site or after injection has occurred would also be required. The renewable fuel producer would be responsible for tracking any leaks that occur after CO_2 capture. We request comment on the type and level of surface and/or subsurface monitoring that would be required to demonstrate long-term storage of CO_2. We also request comment on whether additional monitoring and reporting requirements would be appropriate. For example, whether there should be a requirement for the monitoring and reporting of CO_2 volumes captured, transported, injected and stored, as well as any fugitive emissions released. We seek comment on the appropriateness of establishing a performance standard for CO_2 leakage during transport, injection, and/or geologic storage, and any data that might be available to help develop such a performance standard.

Finally, in order to generate RINs, the renewable fuel producer would have to, at minimum, demonstrate that a sufficient amount of CO_2 was sequestered to reach the appropriate lifecycle GHG threshold. We expect that the regulations would need to specify the minimum fraction of CO_2 emitted that must be captured and stored in order for a renewable fuel producer to qualify for generating RINs. We request comment on whether this approach is appropriate.

E. Applicable Standards

CAA section 211(o)(3) describes how the applicable standards are to be calculated. The only changes made to this provision by EISA are substituting ''transportation fuel'' for gasoline, and reflecting the expanded number of years

[28] More information on the EPA's UIC Program and ongoing research into CCS issues is available at: *http://www.epa.gov/safewater/uic/wells_sequestration.html.*

and additional renewable fuel categories added by Congress in CAA 211(o)(2). In general the form of the standard will not change under RFS2. The renewable fuel standards will continue to be expressed as a volume percentage, and will be used by each refiner, blender or importer to determine their renewable volume obligations. The applicable percentages are set so that if each regulated party meets the percentages, then the amount of renewable fuel, cellulosic biofuel, biomass-based diesel, and advanced biofuel used will meet the volumes specified in Table II.A.1–1.[29]

The new renewable fuel standards would be based on both gasoline and diesel volumes as opposed to only gasoline. Under CAA section 211(o)(3), EPA must determine the refiners, blenders and importers who are subject to the standard. We propose that the standard would apply to refiners, blenders and importers of diesel in addition to gasoline, for both highway and nonroad uses. As described more fully in Section III.F.3, we are proposing at this time that other producers of transportation fuel, such as producers of natural gas, propane, and electricity from fossil fuels, would not be subject to the standard. Since the standard would apply to refiners, blenders and importers of gasoline and diesel, these are also the transportation fuels that would be used to determine the annual volume obligation of the refiner, blender or importer.

The projected volumes of gasoline and diesel used to calculate the standards would continue to be provided by EIA's Short-Term Energy Outlook (STEO). The standards applicable to a given calendar year would be published by November 30 of the previous year. The renewable fuel standards would also continue to take into account various adjustments. For instance, gasoline and diesel volumes would be adjusted to account for the required renewable fuel volumes, and gasoline and diesel volumes produced by small refineries and small refiners would continue to be exempt through 2010.

While the calculation methodology for determination of standards would not change, there would be four separate standards under the new RFS2 program, corresponding to the four separate volume requirements shown in Table II.A.1–1. The specific formulas we propose using to calculate the renewable fuel standards are described below in Section III.E.1.

In order for an obligated party to demonstrate compliance, the percentage standards would be converted into the volume of renewable fuel each obligated party is required to satisfy. This volume of renewable fuel is the volume for which the obligated party is responsible under the RFS program, and would continue to be referred to as its Renewable Volume Obligation (RVO). Since there would be four separate standards under the RFS2 program, there would likewise be four separate RVOs applicable to each refiner, importer, or other obligated party. However, all RVOs would be determined in the same way as described in the current regulations at § 80.1107, with the exception that each standard would apply to the sum of all gasoline and diesel produced or imported as opposed to just the gasoline volume. The formulas we propose using to calculate the RVOs under the RFS2 program are described in Section III.G.1.

1. Calculation of Standards

a. How Would the Standards Be Calculated?

Table II.A.1–1 shows the required overall volumes of four types of renewable fuel specified in EISA. The four separate renewable fuel standards would be based primarily on (1) the 49-state[30] gasoline and diesel consumption volumes projected by EIA, and (2) the total volume of renewable fuels required by EISA for the coming year. Each renewable fuel standard will be expressed as a volume percentage of combined gasoline and diesel sold or introduced into commerce in the U.S., and will be used by each obligated party to determine its renewable volume obligation.

While we are proposing that the standards be based on the sum of all gasoline and diesel, an alternative would split the standards between those that would be specific to gasoline and those that would be specific to diesel. To accomplish this, it would be necessary to project the fraction of the volumes shown in Table II.A.1–1 for cellulosic biofuel, advanced biofuel, and total renewable fuel that would represent gasoline-displacing renewable fuel, and apply this portion of the required volumes to gasoline (by definition the biomass-based diesel standard would have no component relevant to gasoline). The remaining portion would apply to diesel. The result would be seven standards instead of four. This approach to setting standards would more readily align the RFS obligations with the relative amounts of gasoline and diesel produced or imported by each obligated party. For instance, a refiner that produced only diesel fuel would have no obligations under the RFS program for renewable fuels that are used to displace gasoline. However, this alternative approach relies on projections of the relative amounts of gasoline-displacing and diesel-displacing renewable fuels that would need to be updated every year. While such projections would be available through our proposed Production Outlook Reports (see Section III.K), we nevertheless believe that such an approach would unnecessarily complicate the program, and thus we are not proposing it. However, we request comment on it.

In determining the applicable percentages for a calendar year, EISA requires EPA to adjust the standard to prevent the imposition of redundant obligations on any person and to account for renewable fuel use during the previous calendar year by exempt small refineries, defined as refineries that process less than 75,000 bpd of crude oil. As a result, in order to be assured that the percentage standards will in fact result in the volumes shown in Table II.A.1–1, we must make several adjustments to what otherwise would be a simple calculation.

As stated, the renewable fuel standards for a given year are basically the ratio of the amount of each type of renewable fuel specified in EISA for that year to the projected 49-state non-renewable combined gasoline and diesel volume for that year. While the required amount of total renewable fuel for a given year is provided by EISA, the Act requires EPA to use an EIA estimate of the amount of gasoline and diesel that will be sold or introduced into commerce for that year to determine the percentage standards. The levels of the percentage standards would be reduced if Alaska or a U.S. territory chooses to participate in the RFS2 program, as gasoline and diesel produced in or imported into that state or territory would then be subject to the standard.

As mentioned above, we are proposing that EIA's STEO continue to be the source for projected gasoline, and now diesel, consumption estimates. These volumes include renewable fuel use. In order to achieve the volumes of renewable fuels specified in EISA, the gasoline and diesel volumes used to

[29] Actual volumes can vary from the amounts required in the statute. For instance, lower volumes may result if the statutorily required volumes are adjusted downward according to the waiver provisions in CAA 211(o)(7)(D). Also, higher or lower volumes may result depending on the actual consumption of gasoline and diesel in comparison to the projected volumes used to set the standards.

[30] Hawaii opted-in to the original RFS program; that opt-in is carried forward to the proposed new program.

determine the standard must be the non-renewable portion of the gasoline and diesel pools. In order to get total non-renewable gasoline and diesel volumes, we must subtract the total renewable fuel volume from the total gasoline and diesel volume. As with RFS1, the best estimation of the coming year's renewable fuel consumption is found in Table 11 (U.S. Renewable Energy Use by Sector: Base Case) of the STEO.

CAA section 211(o) exempts small refineries [31] from the RFS requirements until the 2011 compliance period. In RFS1, we extended this exemption to the few remaining small refiners not already exempted.[32] Since EPA proposes that small refineries and small refiners continue to be exempt from the program until 2011 under the new RFS2 regulations, EPA will exclude their gasoline and diesel volumes from the overall non-renewable gasoline and diesel volumes used to determine the applicable percentages until 2011. EPA believes this is appropriate because the percentage standards need to be based on the gasoline and diesel subject to the renewable volume obligations, to achieve the overall required volumes of renewable fuel. Because the total small refinery and small refiner gasoline production volume is expected to be fairly constant compared to total U.S. transportation fuel production, we are proposing to estimate small refinery and small refiner gasoline and diesel volumes using a constant percentage of national consumption, as we did in RFS1. Using information from gasoline batch reports submitted to EPA for 2006, EIA data, and input from the California Air Resources Board regarding California small refiners, we estimate that small refinery volumes constitute 11.9% of the gasoline pool, and 15.2% of the diesel pool.

CAA section 211(o) requires that the small refinery adjustment also account for renewable fuels used during the prior year by small refineries that are exempt and do not participate in the RFS2 program. Accounting for this volume of renewable fuel would reduce the total volume of renewable fuel use required of others, and thus directionally would reduce the percentage standard. However, as we discussed in RFS1, the amount of renewable fuel that would qualify, i.e., that was used by exempt small refineries and small refiners but not used as part of the RFS program, is expected to be very small. In fact, these volumes would not significantly change the resulting percentage standards. Whatever renewable fuels small refineries and small refiners blend will be reflected as RINs available in the market; thus there is no need for a separate accounting of their renewable fuel use in the equations used to determine the standards. We thus are proposing, as for RFS1, that this value be zero.

Just as with their corresponding gasoline and diesel volumes, renewable fuels used in Alaska or U.S. territories are not included in the renewable fuel volumes that are subtracted from the total gasoline and diesel volume estimates. Section 211(o) of the Clean Air Act requires that the renewable fuel be consumed in the contiguous 48 states, and any other state or territory that opts in to the program (Hawaii has subsequently opted in). However, because renewable fuel produced in Alaska or a U.S. territory is unlikely to be transported to the contiguous 48 states or to Hawaii, including their renewable fuel volumes in the calculation of the standard would not serve the purpose intended by section 211(o) of the Clean Air Act of ensuring that the statutorily required renewable fuel volumes are consumed in the 48 contiguous states and any state or territory that opts in.

In summary, we are proposing that the total projected non-renewable gasoline and diesel volumes from which the annual standards are calculated be based on EIA projections of gasoline and diesel consumption in the contiguous 48 states and Hawaii, adjusted by constant percentages of 11.9% and 15.2% in 2010 to account for small refinery/refiner gasoline and diesel volumes, respectively, and with built-in correction factors to be used when and if Alaska or a territory opt-in to the program. If actual gasoline and diesel consumption were to exceed the EIA projections, the result would be that renewable fuel volumes would exceed the statutory volumes. Conversely, if actual gasoline and diesel consumption was less than the EIA projection for a given year, actual renewable fuel volumes could be lower than the statutory volumes depending on market conditions. Additional special considerations in establishing the annual cellulosic biofuel standard are discussed below in Section III.E.1.c.

The following formulas will be used to calculate the percentage standards:

$$\mathrm{Std}_{\mathrm{CB,\,i}} = 100\% \times \frac{\mathrm{RFV}_{\mathrm{CB,\,i}}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$\mathrm{Std}_{\mathrm{BBD,\,i}} = 100\% \times \frac{\mathrm{RFV}_{\mathrm{BBD,\,i}}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$\mathrm{Std}_{\mathrm{AB,\,i}} = 100\% \times \frac{\mathrm{RFV}_{\mathrm{AB,\,i}}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$\mathrm{Std}_{\mathrm{RF,\,i}} = 100\% \times \frac{\mathrm{RFV}_{\mathrm{RF,\,i}}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

[31] Under section 211(o) of the Clean Air Act, small refineries are those with 75,000 bbl/day or less average aggregate daily crude oil throughput.

[32] *See* Section IV.B.2.

Where

$Std_{CB,i}$ = The cellulosic biofuel standard for year i, in percent

$Std_{BBD,i}$ = The biomass-based diesel standard for year i, in percent

$Std_{AB,i}$ = The advanced biofuel standard for year i, in percent

$Std_{RF,i}$ = The renewable fuel standard for year i, in percent

$RFV_{CB,i}$ = Annual volume of cellulosic biofuel required by section 211(o)(2)(B) of the Clean Air Act for year i, in gallons

$RFV_{BBD,i}$ = Annual volume of biomass-based diesel required by section 211(o)(2)(B) of the Clean Air Act for year i, in gallons

$RFV_{AB,i}$ = Annual volume of advanced biofuel required by section 211(o)(2)(B) of the Clean Air Act for year i, in gallons

$RFV_{RF,i}$ = Annual volume of renewable fuel required by section 211(o)(2)(B) of the Clean Air Act for year i, in gallons

G_i = Amount of gasoline projected to be used in the 48 contiguous states and Hawaii, in year i, in gallons*

D_i = Amount of diesel projected to be used in the 48 contiguous states and Hawaii, in year i, in gallons

RG_i = Amount of renewable fuel blended into gasoline that is projected to be consumed in the 48 contiguous states and Hawaii, in year i, in gallons

RD_i = Amount of renewable fuel blended into diesel that is projected to be consumed in the 48 contiguous states and Hawaii, in year i, in gallons

GS_i = Amount of gasoline projected to be used in Alaska or a U.S. territory in year i if the state or territory opts in, in gallons*

RGS_i = Amount of renewable fuel blended into gasoline that is projected to be consumed in Alaska or a U.S. territory in year i if the state or territory opts in, in gallons

DS_i = Amount of diesel projected to be used in Alaska or a U.S. territory in year i if the state or territory opts in, in gallons*

RDS_i = Amount of renewable fuel blended into diesel that is projected to be consumed in Alaska or a U.S. territory in year i if the state or territory opts in, in gallons

GE_i = The amount of gasoline projected to be produced by exempt small refineries and small refiners in year i, in gallons, in any year they are exempt per §§ 80.1441 and 80.1442, respectively. Equivalent to $0.119 * (G_i - RG_i)$.

DE_i = The amount of diesel projected to be produced by exempt small refineries and small refiners in year i, in gallons, in any year they are exempt per §§ 80.1441 and 80.1442, respectively. Equivalent to $0.152 * (D_i - RD_i)$.

* Note that these terms for projected volumes of gasoline and diesel use include gasoline and diesel that has been blended with renewable fuel.

b. Proposed Standards for 2010

In today's NPRM we are proposing the specific standards that would apply to all obligated parties in calendar year 2010. We will consider comments received on these standards as part of the comment period associated with today's NPRM, and we intend to issue a **Federal Register** notice by November 30, 2009 setting the applicable standards for 2010. While we are not proposing standards for 2011 and beyond, we present our current projections of these standards in the next section.

Under CAA section 211(o)(7)(D)(i), EPA is required to make a determination each year regarding whether the required volumes of cellulosic biofuel for the following year can be produced. For any calendar year for which the projected volume of cellulosic biofuel production is less than the minimum required volume, the projected volume becomes the basis for the cellulosic biofuel standard. In such a case, the statute also indicates that EPA may also lower the required volumes for advanced biofuel and total renewable fuel.

Based on information available to date, we believe that there are sufficient plans underway to build plants capable of producing 0.1 billion gallons of cellulosic biofuel in 2010, the minimum volume of cellulosic biofuel required by EISA for 2010. Our April 2009 industry assessment concludes that there could be seven small commercial-scale plants online in 2010 (as well as a series of pilot and demonstration plants) capable of producing just over 100 million gallons of cellulosic biofuel. And since the majority of this production (73%) is projected to be cellulosic diesel, the ethanol-equivalent complaince volume could be closer to 145 million gallons. While it is possible that some of these plants could be delayed or a portion of the projected production may not meet the definition of ''cellulosic biofuel'' (due to mixed feedstocks), it is also possible that other plans could proceed ahead of their current schedules. For more on the 2010 cellulosic biofuel production assessment, refer to Section 1.5.3.4 of the DRIA

On the basis of this information, we are not proposing that any portion of the cellulosic biofuel requirement for 2010 be waived. Therefore, we are proposing that the volumes shown in Table II.A.1–1 be used as the basis for the applicable standards for 2010. As described more fully in Section III.E.2 below, we are also proposing that the 2010 standard for biomass-based diesel be based on the combined required volumes for 2009 and 2010, or a total of 1.15 billion gallons. The proposed standards for 2010 are shown in Table III.E.1.b–1.

TABLE III.E.1.b–1—PROPOSED STANDARDS FOR 2010

[Percent]

Cellulosic biofuel	0.06
Biomass-based diesel	0.71
Advanced biofuel	0.59
Renewable fuel	8.01

As described more fully in Section III.E.1.d below, we are proposing that the RFS2 program take effect on January 1, 2010, but we are also taking comment on an effective date later than January 1, 2010, including January 1, 2011 and a mid-2010 effective date. If the RFS2 program became effective mid-2010, the RFS1 program would apply during the first part of 2010 and the RFS2 program would apply for the remainder of the year. We request comment on whether the four proposed standards shown in Table III.E.1.b–1 would apply only to gasoline and diesel produced or imported after the RFS2 effective date or should apply to all gasoline and diesel produced in 2010. We also request comment on whether a single standard for total renewable fuel should apply under RFS1 regulations for the first part of 2010.

c. Projected Standards for Other Years

As discussed above, we intend to set the percentage standards for each upcoming year based on the most recent EIA projections, and using the other sources of information as noted above. We would publish the standard in the **Federal Register** by November 30 of the preceding year. The standards would be used to determine the renewable volume obligations based on an obligated party's total gasoline and diesel production or import volume in a calendar year, January 1 through December 31. An obligated party will calculate its Renewable Volume Obligations (discussed in Section III.G.1) using the annual standards.

For illustrative purposes, we have estimated the standards for 2011 and later based on current information using the formulas discussed above, and assuming no modifications to the annual volumes required.[33] These values are listed below in Table III.E.1.c-1. The required renewable fuel volumes specified in EISA are shown in Table II.A.1–1. The projected gasoline, diesel and renewable fuels volumes were determined from EIA's energy projections. Variables related to Alaska or territory opt-ins were set to zero since we do not have any information related

[33] ''Calculation of the Renewable Fuel Standard for Gasoline and Diesel,'' memo to the docket from Christine Brunner, ASD, OTAQ, EPA, April 2009.

to their participation at this time. No adjustment was made for small refiner or small refinery volumes since their exemption is assumed to end at the end of the 2010 compliance period.

TABLE III.E.1.c–1—PROJECTED STANDARDS UNDER RFS2

[percent]

	Cellulosic biofuel	Biomass-based diesel	Advanced biofuel	Renewable fuel
2011	0.15	0.49	0.83	8.60
2012	0.31	0.61	1.22	9.31
2013	0.61	0.61[a]	1.68	10.09
2014	1.07	0.61[a]	2.28	11.05
2015	1.83	0.61[a]	3.35	12.48
2016	2.58	0.61[a]	4.40	13.49
2017	3.34	0.61[a]	5.46	14.56
2018	4.25	0.61[a]	6.68	15.80
2019	5.19	0.61[a]	7.95	17.11
2020	6.47	0.62[a]	9.25	18.50
2021	8.40	0.62[a]	11.21	20.54
2022	10.07	0.63[a]	13.21	22.65

[a] These projected standards represent the minimum volume of 1.0 billion gallons required by EISA. The actual volume used to set the standard would be determined by EPA through a future rulemaking.

d. Alternative Effective Date

Although we are proposing that the RFS2 regulatory program begin on January 1, 2010 which, depending on timing for the final rule, would allow approximately two months from the anticipated issuance of the rule to its implementation, we seek comment on whether an effective date later than January 1, 2010 would be necessary. If the RFS2 program was not made effective on January 1, 2010, the most straightforward alternative start date would be January 1, 2011. Delaying to 2011 would provide regulated parties additional lead time and would allow all the new requirements and standards to go into effect at the beginning of an annual compliance period. However, delaying to 2011 would also mean that demonstrating compliance with the separate requirements for biomass-based diesel, cellulosic biofuel, and advanced biofuel mandates would not go into effect until 2011. The total renewable fuel mandate in EISA may be able to be implemented with the RFS1 regulations until such time as the RFS2 regulations become effective. However, under the RFS1 regulations, this entire standard would be for conventional biofuels and would be applied to gasoline producers and importers only. There would be no obligation with respect to diesel fuel producers and importers, resulting in a numerically larger standard that would apply to gasoline producers only and which could compel them to market a larger proportion of ethanol as E85 to acquire sufficient RINs for compliance. One possible way to address this issue would be to reduce the 2010 total renewable fuel standard proportionately to reflect the application of the standard only to gasoline producers. However, it does not appear that EPA has statutory authority, or discretion under the RFS1 regulations, to modify the total renewable fuel mandate in this manner. As discussed below in Section III.E.2, any delay beyond January 1, 2010 also has implications for our proposed treatment of the biomass-based diesel volumes required for 2009. EPA invites comment on whether RFS2 implementation should be delayed to January 1, 2011 and, if so, the manner in which the EISA-mandated RFS program should be implemented prior to that date.

Another alternative would be to delay the effective date of the RFS2 program to some time after January 1, 2010 but before January 1, 2011. This alternative would raise the same issues described above (regarding the option of a delay until January 1, 2011) for that portion of 2010 during which RFS2 was not effective. It would also raise additional transition and implementation issues. For instance, we would need to determine whether diesel fuel producers and importers carry a total renewable fuel obligation calculated on the basis of their production for all of 2010 or just the production period in 2010 during which the RFS2 regulations are effective. We would also need to determine whether the 2010 cellulosic biofuel, biomass-based diesel, and advanced biofuel standards applicable under RFS2 should apply to production of gasoline and diesel for all of 2010 or just the production that occurred after the RFS2 regulations were effective If the latter, EPA would need to determine the extent to which RFS1 RINs generated in the first part of 2010 could be used to satisfy RFS2 obligations, given that some 2010 RINs would be generated under the RFS1 requirements while other 2010 RINs would be generated under RFS2 requirements. To accomplish this, RINs generated under the RFS2 requirements would need to be distinguished from RINs generated under RFS1 requirements through the RINs' D codes. Section III.A provides a more detailed description of this alternative approach to the assignment of D codes under the RFS2 program. For additional discussion of how RFS1 RINs would be treated in the transition to the RFS2 program, see our proposed transition approach described in Section III.G.3.

We are requesting comment on all issues related to the option of an RFS2 start date sometime after January 1, 2010, including the need for such a delayed start, the level of the standards, treatment of diesel producers and importers, whether the standards for advanced biofuel, cellulosic biofuel and biomass-based diesel should apply to the entire 2010 production or just the production that would occur after the RFS2 effective date, treatment of the 2009 and/or 2010 biomass-based diesel standard, and the extent to which RFS1 RINs should be valid to show compliance with RFS2 standards.

2. Treatment of Biomass-Based Diesel in 2009 and 2010

We are proposing to make the RFS2 program required through EISA effective on January 1, 2010. The RFS2 program would include an expansion to four separate standards, changes to the RIN system, changes to renewable fuel definitions, the introduction of lifecycle GHG reduction thresholds, and the expansion of obligated parties to include producers and importers of diesel and nonroad fuel. However, EISA requires promulgation of the final RFS2 regulations within one year of enactment and presumes full implementation by January 1, 2009. Moreover, EISA specifies new volume requirements for biomass-based diesel, advanced biofuel, and total renewable fuel for 2009. As described in Section II.A.5, it is not possible to have the full RFS2 program implemented by January 1, 2009. As a result, we must consider how to treat these separate volume requirements for 2009.

a. Proposed Shift in Biomass-Based Diesel Requirement From 2009 to 2010

The statutory language in EISA does not indicate that the existing RFS1 regulations cease to apply on January 1, 2009. Rather, it directs us to ''revise the regulations'' to ensure that the required volumes of renewable fuel are contained in transportation fuel. As a result, until the RFS1 regulations are changed through a notice and comment rulemaking process, they will remain in effect. If the full RFS2 program goes into effect on January 1, 2010, then the existing RFS1 regulations will continue to apply in 2009.

Under RFS1, we set the applicable standard each November for the following compliance period using the required volume of renewable fuel specified in the Clean Air Act, gasoline volume projections from EIA, and the formula provided in the regulations at § 80.1105(d). Since final RFS2 regulations will not be promulgated by the end of 2008, this RFS1 standard-setting process will apply to the 2009 compliance period as well. However, EISA modifies the Clean Air Act to increase the required volume of total renewable fuel for 2009 from 6.1 to 11.1 billion gallons, and thus the applicable standard for 2009, published in November of 2008,[34] reflects this higher volume. This will ensure that the total renewable fuel requirement under EISA for 2009 is implemented.

While the total renewable fuel volume of 11.1 billion gallons will be required in 2009, the existing RFS1 regulations do not provide a mechanism for requiring the 0.5 billion gallons of biomass-based diesel or the 0.6 billion gallons of advanced biofuel required by EISA for 2009. Below we describe our proposed approach for biomass-based diesel. With regard to advanced biofuel, we believe that it is not necessary to implement a separate requirement for the 0.6 billion gallons. Due to the nested nature of the volume requirements, the 0.5 billion gallon requirement for biomass-based diesel would count towards meeting the advanced biofuel requirement, leaving just 0.1 billion gallons that we believe will be supplied through imports of sugar-based ethanol even without a specific mandate for advanced biofuel.

We believe that the deficit carryover provision provides a conceptual mechanism for ensuring that the volume of biomass-based diesel that is required by EISA for 2009 is actually consumed. As described in the RFS1 final rule, the statute permits obligated parties to carry a deficit of any size from one compliance period to the next, so long as a deficit is not carried over two years in a row.[35] In theory this would allow any and all obligated parties to defer compliance with any or all of the 2009 standards until 2010. Based on the precedent set by this statutory provision, we propose that the compliance demonstration for the 2009 biomass-based diesel requirement be extended to 2010. We believe this approach would provide a reasonable transition for biomass-based diesel, given our inability to issue regulations before the beginning of the 2009 calendar year. Our proposed approach would implement the 2009 and 2010 biomass-based diesel volume requirements in a way that ensures that these two years worth of biomass-based diesel would be used, while providing reasonable lead time for obligated parties. It would avoid a transition that fails to have any requirements related to the 2009 biomass-based diesel volume, and instead would require the use of the 2009 volume but would achieve this by extending the compliance period by one year. We believe this is a reasonable exercise of our authority under section 211(o)(2) to issue regulations that ensure that the volumes for 2009 are ultimately used, even though we are unable to issue final regulations prior to the 2009 compliance year. In addition, it is a practical approach that provides obligated parties with appropriate lead time.

To implement our proposed approach, the 2009 requirement of 0.5 billion gallons of biomass-based diesel would be combined with the 2010 requirement of 0.65 billion gallons for a total adjusted 2010 requirement of 1.15 billion gallons of biomass-based diesel. The net effect is that obligated parties can demonstrate compliance with both the 2009 and 2010 biomass-based diesel requirements in 2010, consistent with what the deficit carryover provision would have allowed had we been able to implement the full RFS2 program by January 1, 2009.

Furthermore, we propose to allow all 2009 biodiesel and renewable diesel RINs, identifiable through an RR code of 15 or 17 respectively, to be valid for showing compliance with the adjusted 2010 biomass-based diesel standard of 1.15 billion gallons. This use of previous year RINs for current year compliance would be consistent with our approach to any other standard for any other year and consistent with the flexibility available to any obligated party that carried a deficit from one year to the next. Moreover, it allows an obligated party to acquire sufficient biodiesel and renewable diesel RINs during 2009 to comply with the 0.5 billion gallons requirement, even though their compliance demonstration would not occur until the 2010 compliance period.

While we recognize that RINs generated in 2009 under RFS1 regulations will differ from those generated in 2010 under RFS2 regulations in terms of the purpose of the D code and the other criteria for establishing the eligibility of renewable fuel, we believe that the use of 2009 RINs for compliance with the 2010 adjusted standard is appropriate. It is also consistent with CAA section 211(o)(5), which provides that validly generated credits may be used to show compliance for 12 months. The program transition issue of RINs generated under RFS1 but used to meet standards under RFS2 is discussed in more detail in Section III.G.3 below.

Rather than reducing the 2009 volume requirement for total renewable fuel by 0.5 billion gallons of biomass-based diesel and increasing the 2010 volume requirements for advanced biofuel and total renewable fuel by the same amount, we are proposing that the only standard that would be adjusted would be that for biomass-based diesel in 2010. This approach would minimize the changes to the annual RFS volume requirements and thus would more directly implement the requirements of the statute. However, this approach would also require that we allow 2009 biodiesel and renewable diesel RINs to be used for compliance purposes for both the 2009 total renewable fuel standard as well as the 2010 adjusted biomass-based diesel standard, but not for the 2010 advanced biofuel or total renewable fuel standards. We have

[34] *See* 73 FR 70643.

[35] *See* 72 FR 23935.

identified two possible options for accomplishing this.

i. First Option for Treatment of 2009 Biodiesel and Renewable Diesel RINs

In the first option, an obligated party would add up the 2009 biodiesel and renewable diesel RINs that he used for 2009 compliance with the RFS1 standard for renewable fuel, and reduce his 2010 biomass-based diesel obligation by this amount. Any remaining 2010 biomass-based diesel obligation would need to be covered with either 2009 biodiesel and renewable diesel RINs that were not used for compliance with the renewable fuel standard in 2009, or 2010 biomass-based diesel RINs. This is the option we are proposing in today's notice.

The primary drawback of our proposed option is that 2009 biodiesel and renewable diesel RINs used to demonstrate compliance with the 2009 renewable fuel standard could not be traded to any other party for use in complying with the 2010 biomass-based diesel standard. Thus, for instance, if a refiner acquired many 2009 biodiesel and renewable diesel RINs and used them for compliance with the 2009 renewable fuel standard, and if the number of these 2009 RINs was more than he needed to comply with his 2010 biomass-based diesel obligation, he could not trade the excess to another party. These excess RINs could never be applied to the adjusted 2010 biomass-based diesel standard by any party, and as a result the actual demand for biomass-based diesel could exceed 1.15 bill gal. We believe that obligated parties could avoid this outcome by planning ahead to use no more 2009 biodiesel and renewable diesel RINs for 2009 compliance with the renewable fuel standard than they would need for 2010 compliance with the adjusted biomass-based diesel standard. Moreover, this option could provide obligated parties with sufficient incentive to collect 0.5 billion gallons worth of biodiesel and renewable diesel RINs in 2009 without significant changes to the program's requirements.

ii. Second Option for Treatment of 2009 Biodiesel and Renewable Diesel RINs

Under the second option, biodiesel and renewable diesel RINs generated in 2009 would be allowed to be used for compliance purposes in both 2009 and 2010. To enable this option, for the specific and limited case of biodiesel and renewable diesel RINs generated in 2009, we would modify the regulatory prohibition at § 80.1127(a)(3) limiting the use of RINs for compliance demonstrations to a single compliance year to allow 2009 biodiesel and renewable diesel RINs to be used for compliance purposes in two different years. This change would allow all 2009 biodiesel and renewable diesel RINs to be used to meet the adjusted biomass-based diesel standard in 2010 regardless of whether they were also used to meet the total renewable fuel standard in 2009. We would also need to lift the 20% rollover cap that would otherwise limit the use of 2009 RINs in 2010, and instead allow any number of 2009 biodiesel and renewable diesel RINs to be used to meet the 2010 biomass-based diesel standard.

This option would also require that we implement additional RIN tracking procedures. Under the current RFS1 regulations, RINs used for compliance demonstrations are removed from the RIN market, while under this alternative approach biodiesel and renewable diesel RINs could continue to be valid for compliance purposes vis a vis the adjusted 2010 biomass-based diesel standard even if they were already used for compliance with the renewable fuel standard in 2009. The regulations would need to be changed to allow this, and both EPA's and industry's IT systems would need to be modified to allow for this temporary change.

Due to the additional complexities associated with this option, we are not proposing it. Nevertheless, we request comment on it, as it would more explicitly reflect two separate obligations for calendar year 2009: An RFS1 obligation for total renewable fuel, and an obligation for biomass-based diesel that starts during 2009 with compliance required by the end of 2010 for a volume that covers both 2009 and 2010. We also request comment on whether under this option we should allow 2009 biodiesel and renewable diesel RINs to continue to be bought and sold after 2009 if they are used to demonstrate compliance with the 2009 total renewable fuel standard.

b. Proposed Treatment of Deficit Carryovers and Valid RIN Life For Adjusted 2010 Biomass-Based Diesel Requirement

Although our proposed transition approach is conceptually similar to the statutory deficit carryover provision, the regulatory requirements would not explicitly treat the movement of the 0.5 billion gallons biomass-based diesel requirement from 2009 to 2010 as a deficit carryover. In the absence of any modifications to the deficit carryover provisions, then, an obligated party that did not fully comply with the 2010 biomass-based diesel requirement of 1.15 billion gallons could carry a deficit of any amount into 2011.

If we had been able to implement the 2009 biomass-based diesel volume requirement of 0.5 billion gallons in calendar year 2009, the 2010 biomass-based diesel standard would have been based on 0.65 billion gallons. In this case, the maximum volume of biomass-based diesel that could have been carried into 2011 as a deficit would have been 0.65 billion gallons. In the context of our proposed approach to the treatment of biomass-based diesel in 2009 and 2010, we believe that it would be inappropriate to allow the full 1.15 billion gallons to be carried into 2011 as a deficit. Therefore, we are proposing that obligated parties be prohibited from carrying over a deficit into 2011 larger than 0.65 bill gal. In practice, this would mean that deficit carryovers from 2010 into 2011 for biomass-based diesel could not exceed 57% of an obligated party's 2010 RVO.

Similarly, the combination of the 0.5 billion gallons biomass-based diesel requirement from 2009 with the 2010 volume raises the question of whether 2008 biodiesel or renewable diesel RINs could be used for compliance in 2010 with the adjusted biomass-based diesel standard. Without a change to the regulations, this practice would not be allowed because RINs are only valid for compliances purposes for the year generated or the year after. However, if we had been able to implement the full RFS2 program for the 2009 compliance year, 2008 biodiesel and renewable diesel RINs would be valid for compliance with the 0.5 billion gallons biomass-based diesel requirement. Therefore, we are proposing to modify the regulations to allow excess 2008 biodiesel and renewable diesel RINs to be used for compliance purposes in 2009 or 2010. We request comment on this proposal.

We also propose that the 20% rollover cap would continue to apply in all years as described in more detail in Section IV.D. However, we are proposing an additional constraint in the application of this cap to the biomass-based diesel obligation in the 2010 compliance year. If the 2009 biomass-based diesel volume requirement of 0.5 billion gallons could have been required in 2009, the use of excess 2008 biodiesel and renewable diesel RINs would have been limited to 20% of the 2009 requirement, or a maximum of 0.1 billion gallons. Since we are proposing to require that the 2009 and 2010 biomass-based diesel requirements be combined for a total of 1.15 billion gallons, we propose that the maximum allowable portion that could be derived from 2008 biomass-based diesel RINs would be 0.1 billion gallons. This would represent 8.7% of the 2010 obligation ($^{0.1}/_{1.15}$). In addition to this limit on the use of 2008 RINs for 2010 compliance that is unique to this option, the 20% rollover cap would continue to apply to the use of all previous-year RINs used for compliance purposes in 2010. Thus, the total number of all 2008 and 2009 RINs that could be used to meet the 2010 biomass-based diesel obligation would continue to be capped at 20%. We request comment on this approach.

Finally, we are proposing to allow 2009 RINs that are retired because they are ultimately used for nonroad or home heating oil purposes to be valid for compliance with the 2010 RFS standard. Currently, under RFS1, RINs associated with renewable fuel that is not ultimately used as motor vehicle fuel must be retired. In contrast, under EISA, renewable fuel used for nonroad purposes, except for use in industrial boilers or ocean-going vessels, is considered transportation fuel, and is eligible for the RFS program. We are proposing that 2009 RINs generated for renewable fuel that is ultimately used for nonroad or home heating oil purposes continue to be retired by the appropriate party pursuant to 80.1129(e). However, we are proposing that those retired 2009 nonroad or home heating oil RINs be eligible for reinstatement by the retiring party in 2010. These reinstated RINs may be used by that party to demonstrate compliance with a 2010 RVO, or for sale to other parties who would then use the RINs for compliance purposes. While we anticipate that this proposed provision would be utilized largely for biodiesel RINs that were retired by parties that sold them for use as nonroad fuel or home heating oil, we propose that the provision apply to all RINs. We request comment on this proposed approach.

c. Alternative Approach to Treatment of Biomass-Based Diesel in 2009 and 2010

Under our proposed approach, the 0.5 billion gallon requirement for biomass-based diesel in 2009 would be added to the 0.65 billion gallon requirement for 2010, and the total volume of 1.15 billion gallons would be used as the basis of a single adjusted standard applicable to obligated parties in 2010. The compliance demonstration for this single standard would need to be made by February 28, 2011. As an alternative, we could establish two separate biomass-based diesel standards for which compliance must be demonstrated by February 28, 2011. One of these standards would be based on 0.65 billion gallons and would represent the applicable biomass-based diesel standard for 2010. The other standard would be based on 0.5 billion gallons and would represent the applicable biomass-based diesel standard for 2009. In essence, the standard based on 0.5 billion gallons would be for the 2009 calendar year even though we would extend its compliance demonstration until February 28, 2011.

In this alternative, only excess 2008 or 2009 biodiesel and renewable diesel RINs could be used to comply with the standard based on 0.5 billion gallons. Excess 2009 biodiesel or renewable diesel RINs and 2010 biomass-based diesel RINs could be used to comply with the standard based on 0.65 billion gallons. The 20% rollover cap would apply to both standards. As a result, this alternative approach would effectively implement the 2009 biomass-based diesel standard in calendar year 2009, and thus it may come closer to the statute's requirements than our proposed approach. Moreover, the existing provisions for the valid life of RINs and deficit carryover would not need modification as they would under our proposed approach.

However, this alternative would arguably provide less than appropriate lead time for meeting the 0.5 billion gallon obligation, as it would require obligated parties to begin acquiring sufficient 2008 and 2009 biodiesel and renewable diesel RINs starting in January of 2009 even though our final rulemaking is not expected to be issued until the fall of 2009. There are two reasons that this lead time might nevertheless be considered appropriate. First, obligated parties could wait until the final rule is published to begin acquiring 2008 and 2009 biodiesel and renewable diesel RINs. Moreover, they would not need to demonstrate compliance with the 0.5 billion gallons standard until February 28, 2011, providing ample time to locate and acquire sufficient RINs. Second, the deficit carryover provisions would allow obligated parties to treat the separate 0.5 and 0.65 billion gallon requirements as a single requirement that must be met in total by February 28, 2011. In this sense, this alternative is similar to our proposed approach. We request comment on this alternative approach.

d. Treatment of Biomass-Based Diesel Under an RFS2 Effective Date Other Than January 1, 2010

The above discussion assumes that the RFS2 program is effective on January 1, 2010. If the program effective date is delayed, similar issues arise regarding whether EISA volume mandates for fuel categories with no mandates under RFS1 are lost, or should be recaptured through a delayed compliance demonstration in the first year of the RFS2 program. For a delay beyond January 1, 2010, the issues relate to cellulosic biofuel and advanced biofuel in addition to biomass-based diesel.

For instance, our proposed approach to biomass-based diesel effectively makes the one-year deficit carryover a necessary element of compliance for 2010, and maintains the two-year valid life of RINs. However, if the effective date of RFS2 were delayed to January 1, 2011, we could not take the same approach. By requiring compliance demonstrations to be made in 2011 for the required biomass-based diesel volumes mandated for 2009, 2010, and 2011, we would be effectively requiring a 2-year deficit carryover and a three-year valid life of RINs, contrary to the statutory limitations. As an alternative, one possible approach would be to only sum the required biomass-based diesel volumes for 2010 and 2011 and require compliance demonstrations at the end of 2011.

If the RFS2 program became effective in mid-2010, we would also need to determine the appropriate level of the biomass-based diesel standard, and whether it would apply to gasoline and diesel volumes produced only after the RFS2 effective date, or all gasoline and diesel volumes produced in 2010.

EPA invites comment on whether and how it should recapture these volume mandates under different start-date scenarios.

F. Fuels That Are Subject to the Standards

Under RFS1, producers and importers of gasoline are obligated parties subject to the standards. Any party that produces or imports only diesel fuel is not subject to the standards. EISA changes this provision by expanding the RFS program in general to include transportation fuel. As discussed above, however, section 211(o)(3) continues to require EPA to determine which refiners, blenders, and importers are treated as subject to the standard. As described further in Section III.G below, we are proposing that the sum of all highway and nonroad gasoline and diesel fuel produced or imported within a calendar year be the basis on which the RVOs are calculated. This section provides our proposed definition of gasoline and diesel for the purposes of the RFS program.

1. Gasoline

As with the RFS1 program, the volume of gasoline used in calculating the RVO under RFS2 would continue to include all finished gasoline (reformulated gasoline (RFG) and conventional gasoline (CG)) produced or imported for use in the contiguous United States or Hawaii, as well as all unfinished gasoline that becomes finished gasoline upon the addition of oxygenate blended downstream from the refinery or importer. This would include both unfinished reformulated gasoline, called ''reformulated gasoline blendstock for oxygenate blending,'' or ''RBOB,'' and unfinished conventional gasoline designed for downstream oxygenate blending (e.g., sub-octane conventional gasoline), called ''CBOB.'' The volume of any other unfinished gasoline or blendstock, such as butane or naphtha produced in a refinery, would not be included in the obligated volume, except where the blendstock is combined with other blendstock or gasoline to produce finished gasoline, RBOB, or CBOB. Where a blendstock is blended with other blendstock to produce finished gasoline, RBOB, or CBOB, the total volume of the gasoline blend would be included in the volume used to determine the blender's renewable fuels obligation. Where a blendstock is added to finished gasoline, only the volume of the blendstock would be included, since the finished gasoline would have been included in the compliance determinations of the refiner or importer of the gasoline. For purposes of this preamble, the various gasoline products described above that we are proposing to include in a party's obligated volume would collectively be called ''gasoline.''

Also consistent with the RFS1 program, we propose to continue to exclude any volume of renewable fuel contained in gasoline from the volume of gasoline used to determine the renewable fuels obligations. This exclusion would apply to any renewable fuels that are blended into gasoline at a refinery, contained in imported gasoline, or added at a downstream location. Thus, for example, any ethanol added to RBOB or CBOB at a refinery's rack or terminal downstream from the refinery or importer would be excluded from the volume of gasoline used by the refiner or importer to determine the obligation. This is consistent with how the standard itself is calculated—EPA determines the applicable percentage by comparing the overall projected volume of gasoline used to the overall renewable fuel volume that is specified in EPAct, and EPA excludes ethanol and other renewable fuels that blended into the gasoline in determining the overall projected volume of gasoline. When an obligated party determines their RVO by applying the applicable percentage to the amount of gasoline they produce or import, it is consistent to also exclude ethanol and other renewable fuel blends from the calculation of the volume of gasoline produced.

As with the RFS1 program, we are proposing that Gasoline Treated as Blendstock (GTAB) would continue to be treated as a blendstock under the RFS2 program, and thus would not count towards a party's renewable fuel obligation. Where the GTAB is blended with other blendstock (other than renewable fuel) to produce gasoline, the total volume of the gasoline blend, including the GTAB, would be included in the volume of gasoline used to determine the renewable fuel obligation. Where GTAB is blended with renewable fuel to produce gasoline, only the GTAB volume would be included in the volume of gasoline used to determine the renewable fuel obligation. Where the GTAB is blended with finished gasoline, only the GTAB volume would be included in the volume of gasoline used to determine the renewable fuel obligation.

2. Diesel

As discussed above in Section II.A.4, EISA expanded the RFS program to include transportation fuels other than gasoline, and we are proposing that both highway and nonroad diesel be used in calculating a party's RVO. We are proposing that any party that produces or imports petroleum-based diesel fuel that is designated as motor vehicle, nonroad, locomotive, and marine diesel fuel (MVNRLM) (or any subcategory of MVNRLM) would be required to include the volume of that diesel fuel in the determination of its RVO under the RFS2 rule. We are proposing that diesel fuel would include any distillate fuel that meets the definition of MVNRLM diesel fuel as it has already been defined in the regulations at § 80.2(qqq), including any subcategories such as MV (motor vehicle diesel produced for use in highway diesel engines and vehicles), NRLM (diesel produced for use in nonroad, locomotive, and marine diesel engines and equipment/vessels), NR (diesel produced for use in nonroad engines and equipment), and LM (diesel produced for use in locomotives and marine diesel engines and vessels).[36]

We are proposing that transportation fuels meeting the definition of MVNRLM would be used to calculate the RVOs, and refiners, blenders, or importers of MVNRLM would be treated as obligated parties. As such, diesel fuel that is designated as heating oil, jet fuel, or any designation other than MVNRLM or a subcategory of MVNRLM, would not be subject to the applicable percentage standard and would not be used to calculate the RVOs.[37]

We are also requesting comment on the idea that any diesel fuel not meeting these requirements, such as distillate or residual fuel intended solely for use in ocean-going vessels, would not be used to calculate the RVOs. As discussed above in Section II.A.4, EISA specifies that ''transportation fuels'' do not include fuels for use in ocean-going vessels. We are interpreting the term ''ocean-going vessel'' to mean those vessels that are powered by Category 3 (C3) marine engines and that use residual fuel or operate internationally; we request comment on this interpretation. As such, we are requesting comment on the concept that fuel intended solely for use in ocean-going vessels, or that an obligated party can verify as having been used in an ocean-going vessel, would be excluded from the renewable fuel standards. Further, we are also requesting comment on whether fuel used on such vessels with C2 engines should also be excluded from the renewable fuel standards, and how such an exemption should be phrased.

3. Other Transportation Fuels

As discussed further in Section III.J.3, below, we propose that transportation fuels other than gasoline or MVNRLM diesel fuel (natural gas, propane, and electricity) would not be used to calculate the RVOs of any obligated party. We believe this is a reasonable way to implement the obligations of 211(o)(3) because the volumes are small and the producers cannot readily differentiate the small transport portion from the large non-transport portion (in fact, the producer may have no knowledge of its use in transport); we will reconsider this approach if and when these volumes grow. At the same time, it is clear that other fuels can meet the definition of ''transportation fuel,'' and we are proposing that under certain

[36] EPA's diesel fuel regulations use the term ''nonroad'' to designate one large category of land-based off-highway engines and vehicles, recognizing that locomotive and marine engines and vessels are also nonroad engines and vehicles under EPAct's definition of nonroad. Except where noted, the discussion of nonroad in reference to transportation fuel includes the entire category covered by EPAct's definition of nonroad.

[37] *See* 40 CFR 80.598(a) for the kinds of fuel types used by refiners or importers in designating their diesel fuel.

circumstances, producers or generators of such other transportation fuels may generate RINs as a producer or importer of a renewable fuel. See Section III.B.1.a for further discussion of other RIN-generating fuels.

G. Renewable Volume Obligations (RVOs)

Under the current RFS program, each obligated party must determine its RVO based on the applicable percentage standard and its annual gasoline volume. The RVO represents the volume of renewable fuel that the obligated party must ensure is used in the U.S. in a given calendar year. Obligated parties must meet their RVO through the accumulation of RINs which represent the amount of renewable fuel used as motor vehicle fuel that is sold or introduced into commerce within the U.S. Each gallon-RIN would count as one gallon of renewable fuel for compliance purposes.

We propose to maintain this approach to compliance under the RFS2 program. One primary difference between the current and new RFS programs in terms of demonstrating compliance would be that each obligated party would now have four RVOs instead of one (through 2012) or two (starting in 2013) under the RFS1 program. Also, as discussed above, RVOs would be calculated based on production or importation of both gasoline and diesel fuels, rather than gasoline alone.

By acquiring RINs and applying them to their RVOs, obligated parties are effectively causing the renewable fuel represented by the RINs to be consumed as transportation fuel in highway or nonroad vehicles or engines. Obligated parties would not be required to physically blend the renewable fuel into gasoline or diesel fuel themselves. The accumulation of RINs would continue to be the means through which each obligated party shows compliance with its RVOs and thus with the renewable fuel standards.

If an obligated party acquires more RINs than it needs to meet its RVOs, then in general it could retain the excess RINs for use in complying with its RVOs in the following year or transfer the excess RINs to another party. If, alternatively, an obligated party has not acquired sufficient RINs to meet its RVOs, then under certain conditions it could carry a deficit into the next year.

This section describes our proposed approach to the calculation of RVOs under RFS2 and the RINs that would be valid for demonstrating compliance with those RVOs. This includes a description of the special treatment that must be applied to 2009 RINs used for compliance purposes in 2010, since RINs generated in 2009 under RFS1 would not be exactly the same as those generated in 2010 under RFS2. We also describe an alternative approach to the identification of obligated parties that would place the obligations under RFS2 on only finished gasoline and diesel rather than on certain blendstocks and unfinished fuels as well. The implication of this would be that the final blender of the gasoline or diesel would be the obligated parties rather than producers of blendstocks and unfinished fuels.

1. Determination of RVOs Corresponding to the Four Standards

In order for an obligated party to demonstrate compliance, the percentage standards described in Section III.E.1 which are applicable to all obligated parties must be converted into the volumes of renewable fuel each obligated party is required to satisfy. These volumes of renewable fuel are the volumes for which the obligated party is responsible under the RFS program, and are referred to here as its RVO. Under RFS2, each obligated party would need to acquire sufficient RINs each year to meet each of the four RVOs corresponding to the four renewable fuel standards.

The calculation of the RVOs under RFS2 would follow the same format as the existing formulas in the regulations at § 80.1107(a), with one modification. The standards for a particular compliance year would be multiplied by the sum of the gasoline and diesel volume produced or imported by an obligated party in that year rather than only the gasoline volume as under the current program.[38] To the degree that an obligated party did not demonstrate full compliance with its RVOs for the previous year, the shortfall would be included as a deficit carryover in the calculation. CAA section 211(o)(5) only permits a deficit carryover from one year to the next if the obligated party achieves full compliance with its RVO including the deficit carryover in the second year. Thus deficit carryovers could not occur two years in succession for any of the four standards. They could, however, occur as frequently as every other year for a given obligated party.

Note that a party that produces only diesel fuel would have an obligation for all four standards even though he would not have the opportunity to blend ethanol into his own gasoline. Likewise, a party that produces only gasoline will have an obligation for all four standards even though he would not have an opportunity to blend biomass-based diesel into his own diesel fuel. Although these circumstances might imply that the four standards should be further subdivided into gasoline-specific and diesel-specific standards, we do not believe that this would be appropriate as described in Section III.E.1. Instead, since the obligations are met through the use of RINs, compliance with the standards does not require an obligated party to blend renewable fuel into their own or anyone else's gasoline or diesel fuel.

2. RINs Eligible To Meet Each RVO

Under RFS1, all RINs had the same compliance value and thus it did not matter what the RR or D code was for a given RIN when using that RIN to meet the total renewable fuel standard. In contrast, under RFS2 only RINs with specified D codes could be used to meet each of the four standards.

As described in Section II.A.1, the volume requirements in EISA are generally nested within one another, so that the advanced biofuel requirement includes fuel that meets either the cellulosic biofuel or the biomass-based diesel requirements, and the total renewable fuel requirement includes fuel that meets the advanced biofuel requirement. As a result, the RINs that can be used to meet the four standards are likewise nested. Using the proposed D codes defined in Table III.A–1, the RINs that could be used to meet each of the four standards are shown in Table III.G.2–1.

TABLE III.G.2–1—RINS THAT CAN BE USED TO MEET EACH STANDARD

Standard	Obligation	Allowable D codes
Cellulosic biofuel	RVO_{CB}	1.

[38] As discussed above, the diesel fuel that is used to calculate the RVO is any diesel designated as MVNRLM or a subcategory of MVNRLM.

TABLE III.G.2–1—RINS THAT CAN BE USED TO MEET EACH STANDARD—Continued

Standard	Obligation	Allowable D codes
Biomass-based diesel	RVO_{BBD}	2.
Advanced biofuel	RVO_{AB}	1, 2, and 3.
Renewable fuel	RVO_{RF}	1, 2, 3, and 4.

The nested nature of the four standards also means that we must allow the same RIN to be used to meet more than one standard in the same year. Thus, for instance, a RIN with a D code of 1 could be used to meet three of the four standards, while a RIN with a D code of 3 could be used to meet both the advanced biofuel and total renewable fuel standards. However, we propose continuing to prohibit the use of a single RIN for compliance purposes in more than one year or by more than one party.[39]

3. Treatment of RFS1 RINs Under RFS2

As described in Section II.A, we are proposing a number of changes to the RFS program as a result of the requirements in EISA. These changes would go into effect on January 1, 2010 and, among other things, would affect the conditions under which RINs are generated and their applicability to each of the four standards. As a result, RINs generated in 2010 under RFS2 will not be exactly the same as RINs generated in 2009 under RFS1. Given the valid RIN life that allows a RIN to be used in the year generated or the year after, we must address circumstances in which excess 2009 RINs are used for compliance purposes in 2010. We must also address deficit carryovers from 2009 to 2010, since the total renewable fuel standards in these two years will be defined differently.

a. Use of 2009 RINs in 2010

In 2009, the RFS1 regulations will continue to apply and thus producers will not be required to demonstrate that their renewable fuel is made from renewable biomass as defined by EISA, nor that their combination of fuel type, feedstock, and process meets the GHG thresholds specified in EISA. Moreover, there is no practical way to determine after the fact if RINs generated in 2009 meet any of these criteria. However, we believe that the vast majority of RINs generated in 2009 would in fact meet the RFS2 requirements. First, while ethanol made from corn must meet a 20% GHG threshold under RFS2 if produced by a facility that commenced construction after December 19, 2007, facilities that were already built or had commenced construction as of December 19, 2007 are exempt from this requirement. Essentially all ethanol produced in 2009 will meet the prerequisites for this exemption. Second, it is unlikely that renewable fuels produced in 2009 will have been made from feedstocks grown on agricultural land that had not been cleared or cultivated prior to December 19, 2007. In the intervening time period, it is much more likely that the additional feedstocks needed for renewable fuel production would come from existing cropland or cropland that has lain fallow for some time. Finally, the text of section 211(o)(5) states that a ''credit generated under this paragraph shall be valid to show compliance for the 12 months as of the date of generation,'' and EISA did not change this provision and did not specify any particular transition protocol to follow. A straightforward interpretation of this provision is to allow 2009 RINs to be valid to show compliance for 2010 obligations.

Since there will be separate standards for cellulosic biofuel and biomass-based diesel in 2010, RINs generated in 2009 that could be used to meet either of these two 2010 standards should meet the GHG thresholds of 60% and 50%, respectively. While we will not have a mechanism in place to determine if these thresholds have been met for RINs generated in 2009, and there are indications from our assessment of lifecycle GHG performance that at least some renewable fuels produced in 2009 would not meet these thresholds, nevertheless any shortfall in GHG performance for this one transition year is unlikely to have a significant impact on long-term GHG benefits of the program. Based on our belief that it is critical to the smooth operation of the program that excess 2009 RINs be allowed to be used for compliance purposes in 2010, we are proposing that RINs generated in 2009 to represent cellulosic biomass ethanol whose GHG performance has not been verified would still be valid for use for 2010 compliance purposes for the cellulosic biofuel standard. Likewise, we are proposing that RINs generated in 2009 to represent biodiesel and renewable diesel whose GHG performance has not been verified would still be valid for use for 2010 compliance purposes for the biomass-based diesel standard. We request comment on this approach.

We propose to use information contained in the RR and D codes of RFS1 RINs to determine how those RINs should be treated under RFS2. The RR code is used to identify the Equivalence Value of each renewable fuel, and under RFS1 these Equivalence Values are unique to specific types of renewable fuel. For instance, biodiesel (mono alkyl ester) has an Equivalence Value of 1.5, and non-ester renewable diesel has an Equivalence Value of 1.7, and both of these fuels may be valid for meeting the biomass-based diesel standard under RFS2. Likewise, RINs generated for cellulosic biomass ethanol in 2009 must be identified with a D code of 1, and these fuels may be valid for meeting the cellulosic biofuel standard under RFS2. Our proposed treatment of 2009 RINs in 2010 is shown in Table III.G.3.a–1.

TABLE III.G.3.a–1—PROPOSED TREATMENT OF EXCESS 2009 RINS IN 2010

Excess 2009 RINs	Treatment in 2010
RFS1 RINs with RR code of 15 or 17.	Equivalent to RFS2 RINs with D code of 2.
RFS1 RINs with D code of 1.	Equivalent to RFS2 RINs with D code of 1.
All other RFS1 RINs	Equivalent to RFS2 RINs with D code of 4.

Although we have discussed the issue of RFS1 RINs being used for RFS2 purposes in the context of our proposal that the RFS2 program be effective on January 1, 2010, we would expect a similar treatment of RFS1 RINs for RFS2 compliance purposes if the RFS2 effective date is delayed. In that case RFS1 RINs generated in 2010 would be available to show compliance for both the 2010 and 2011 compliance years, in a manner similar to that described above.

[39] Note that we are proposing an exception to this general prohibition for the specific and limited case of excess 2008 and 2009 biodiesel and renewable diesel RINs used to demonstrate compliance with both the 2009 total renewable fuel standard and the 2010 biomass-based diesel standard. *See* Section III.E.2.a.

b. Deficit Carryovers From the RFS1 Program to RFS2

If the RFS2 program goes into effect on January 1, 2010, the calculation of RVOs in 2009 under the existing regulations will be somewhat different than the calculation of RVOs in 2010 under RFS2. In particular, 2009 RVOs will be based upon gasoline production only, while 2010 RVOs would be based on volumes of gasoline and diesel. As a result, 2010 compliance demonstrations that include a deficit carried over from 2009 will combine obligations calculated on two different bases.

We do not believe that deficits carried over from 2009 to 2010 would undermine the goals of the program in requiring specific volumes of renewable fuel to be used each year. Although RVOs in 2009 and 2010 would be calculated differently, obligated parties must acquire sufficient RINs in 2010 to cover any deficit carried over from 2009 in addition to that portion of their 2010 obligation which is based on their 2010 gasoline and diesel production. As a result, the 2009 nationwide volume requirement of 11.1 billion gallons of renewable fuel will be consumed over the two year period concluding at the end of 2010. Thus, we are not proposing special treatment for deficits carried over from 2009 to 2010.

We propose that a deficit carried over from 2009 to 2010 would only affect a party's total renewable fuel obligation in 2010 ($RVO_{RF,i}$ as discussed in Section III.G.1), as the 2009 obligation is for total renewable fuel use, not a subcategory. The RVOs for cellulosic biofuel, biomass-based diesel, or advanced biofuel would not be affected, as they do not have parallel obligations in 2009 under RFS1.

If the RFS2 start date is delayed to be later than January 1, 2010, we expect that the same principles described above would apply for any deficit calculated under the RFS1 program and carried forward to RFS2.

4. Alternative Approach to Designation of Obligated Parties

Under RFS1, obligated parties who are subject to the standard are those that produce or import finished gasoline (RFG and conventional) or unfinished gasoline that becomes finished gasoline upon the addition of an oxygenate blended downstream from the refinery or importer. Unfinished gasoline includes reformulated gasoline blendstock for oxygenate blending (RBOB), and conventional gasoline blendstock designed for downstream oxygenate blending (CBOB) which is generally sub-octane conventional gasoline. The volume of any other unfinished gasoline or blendstock, such as butane, is not included in the volume used to determine the RVO, except where the blendstock is combined with other blendstock or finished gasoline to produce finished gasoline, RBOB, or CBOB. Thus, parties downstream of a refinery or importer are only obligated parties to the degree that they use non-renewable blendstocks to make finished gasoline, RBOB, or CBOB.

The approach we took for RFS1 was based on our expectation at that time that there would be an excess of RINs at low cost, and our belief that the ability of RINs to be traded freely between any parties once separated from renewable fuel would provide ample opportunity for parties who were in need of RINs to acquire them from parties who had excess. We also pointed out that the designation of ethanol blenders as obligated parties would have greatly expanded the number of regulated parties and increased the complexity of the RFS program beyond that which was necessary to carry out the renewable fuels mandate under CAA section 211(o).

Following the new requirements under EISA, the required volumes of renewable fuel will be increasing significantly above the levels required under RFS1. These higher volumes are already resulting in changes in the demand for RINs and operation of the RIN market. First, obligated parties who have excess RINs are increasingly opting to retain rather than sell them to ensure they have a sufficient number for the next year's compliance. Second, since all gasoline is expected to contain ethanol by 2013, few blenders would be able to avoid taking ownership of RINs by that time under the existing definition of obligated party. As a result, by 2013 essentially every blender would be a regulated party who is subject to recordkeeping and reporting requirements, and thus the additional burden of demonstrating compliance with the standard could be small. Third, major integrated refiners who operate gasoline marketing operations have direct access to RINs for ethanol blended into their gasoline, while refiners whose operations are focused primarily on producing refined products do not have such direct access to RINs. The result is that in some cases there are significant disparities between obligated parties in terms of opportunities to acquire RINs. If those that have excess RINs are reluctant to sell them, those who are seeking RINs may be forced to market a disproportionate share of E85 in order to gain access to the RINs they need for compliance. If obligated parties seeking RINs cannot acquire a sufficient number, they can only carry a deficit into the following year, after which they would be in noncompliance if they could not acquire sufficient RINs. The result might be a much higher price for RINs (and fuel) in the marketplace than would be expected under a more liquid market.

Given the change in circumstances brought about through EISA, it may be appropriate to consider a change in the way that obligated parties are defined to more evenly align a party's access to RINs with that party's obligations under the RFS2 program. The most straightforward approach would be to eliminate RBOB and CBOB from the list of fuels that are subject to the standard, such that a party's RVO would be based only on the non-renewable volume of finished gasoline or diesel that he produces or imports. Parties that blend ethanol into RBOB and CBOB to make finished gasoline would thus be obligated parties, and their RVOs would be based upon the volume of RBOB and CBOB prior to ethanol blending. Traditional refiners that convert crude oil into transportation fuels would only have an RVO to the degree that they produced finished gasoline or diesel, with all RBOB and CBOB sold to another party being excluded from the calculation of their RVO.

Since essentially all gasoline is expected to be E10 within the next few years (*see* discussion in Section V.D.2 below), this approach would effectively shift the obligation for all gasoline from refiners and importers to ethanol blenders (who in many cases are still the refiners). However, this approach by itself would maintain the obligation for diesel on refiners and importers. Thus, a variation of this approach would be to move the obligations for all gasoline and diesel downstream to parties who supply finished transportation fuels to retail outlets or to wholesale purchaser-consumer facilities. This variation would have the additional effect of more closely aligning obligations and access to RINs for parties that blend biodiesel and renewable diesel into petroleum-based diesel.

We are not proposing to eliminate RBOB and CBOB from the list of fuels that are subject to the standard in today's notice since it would result in a significant change in the number of obligated parties and the movement of RINs. Many parties that are not obligated under the current RFS program would become obligated, and would be forced to implement new systems for determining and reporting compliance. Nevertheless, it would have certain advantages. Currently, blenders that are not obligated parties are profiting from the sale of RINs they acquire through splash blending of ethanol. By eliminating RBOB and CBOB from the list of obligated fuels, these blenders would become directly responsible for ensuring that the volume requirements of the RFS program are met, and the cost of meeting the standard would be more evenly distributed among parties that blend renewable fuel into gasoline. With obligations placed more closely to the points in the distribution system where RINs are made available, the overall market prices for RINs may be lowered and consequently the cost of the program to consumers may be reduced.

While eliminating the categories of RBOB and CBOB from the list of obligated fuels would result in a significant change in the distribution of obligations among transportation fuel producers, it could help to ensure that the RIN market functions as we originally intended. As a result, RINs would more directly be made available to the parties that need them for compliance. This is similar to the goal of the direct transfer approach to RIN distribution as described in the proposed rulemaking for the RFS1 program and presented again in Section III.H.4 below. We request comment on the degree to which access to RINs is a concern among current obligated parties. Since either the elimination of RBOB and CBOB from the list of obligated fuels or the direct transfer approach to RIN distribution could both accomplish the same goal, we request comment on which one would be more appropriate, if any.

We have also considered a number of alternative approaches that could be used to help ensure that obligated parties can demonstrate compliance. For instance, one alternative approach would leave our proposed definitions for obligated parties in place, but would add a regulatory requirement that any party who blends ethanol into RBOB or CBOB must transfer the RINs associated with the ethanol to the original producer of the RBOB or CBOB. However, we believe that such an approach would be both inappropriate and difficult to implement. RBOB and CBOB is often transferred between multiple parties prior to ethanol blending. As a result, a regulatory requirement for RIN transfers back to the original producer would necessitate an additional tracking requirement for RBOB and CBOB so that the blender would know the identity of the original producer. It would also be difficult to ensure that RINs representing the specific category of renewable fuel blended were transferred to the producer of the RBOB or CBOB, given the fungible nature of RINs assigned to batches of renewable fuel. For these reasons, we do not believe that this alternative approach would be appropriate.

In another alternative approach, some RINs that expire without being used for compliance by an obligated party could be used to reduce the nationwide volume of renewable fuel required in the following year. We would only reduce the required volume of renewable fuel to the degree that sufficient RINs had been generated to permit all obligated parties to demonstrate compliance, but some obligated parties nevertheless could not acquire a sufficient number of RINs. Moreover, only RINs that were expiring would be used to reduce the nationwide volume for the next year. This alternative approach would ensure that the volumes required in the statute would actually be produced and would prevent the hoarding of RINs from driving up demand for renewable fuel. However, it would also reduce the impact of the valid life limit for RINs.

We could lower the 20% rollover cap applicable to the use of previous-year RINs to a lower value, such as 10%. This approach would provide a greater incentive for obligated parties with excess RINs to sell them but would further restrict a potentially useful means of managing an obligated party's risk. As described in Section IV.D, we are not proposing any changes in the 20% rollover cap in today's notice. However, we request comment on it.

Finally, another change to the program that would not change the definition of obligated parties, but could help address the disparity of access to RINs among obligated parties, would be to remove the requirement developed under RFS1 that RINs be transferred with renewable fuel volume by the renewable fuel producers and importers. This alternative is discussed further in Section III.H.4 below.

H. Separation of RINs

We propose that most of the RFS1 provisions regarding the separation of RINs from volumes of renewable fuel be retained for RFS2. However, the modifications in EISA will require a number of changes, primarily to the treatment of RINs associated with nonroad renewable fuel and renewable fuels used in heating oil and jet fuel. Our approach to the separation of RINs by exporters must also be modified to account for the fact that there would be four categories of renewable fuel under RFS2.

1. Nonroad

Under RFS1, RINs associated with renewable fuels used in nonroad vehicles and engines downstream of the renewable fuel producer are required to be retired by the party who owns the renewable fuel at the time of blending. This provision derived from the EPAct definition of renewable fuel which was limited to fuel used to replace fossil fuel used in a motor vehicle. EISA however expands the definition of renewable fuel, and ties it to the definition of transportation fuel, which is defined as any ''fuel for use in motor vehicles, motor vehicle engines, nonroad vehicles, or nonroad engines (except for ocean-going vessels). To implement these changes, the proposed RFS2 program eliminates the RFS1 RIN retirement requirement for renewable fuels used in nonroad applications, with the exception of RINs associated with renewable fuels used in ocean-going vessels.

2. Heating Oil and Jet Fuel

EISA defined 'additional renewable fuel' as ''fuel that is produced from renewable biomass and that is used to replace or reduce the quantity of fossil fuel present in home heating oil or jet fuel.'' [40] While we are proposing that fossil-based heating oil and jet fuel would not be included in the fuel used by a refiner or importer to calculate their RVO, we are proposing that renewable fuels used as or in heating oil and jet fuel may generate RINs for credit purposes. Thus, the RINs of a renewable fuel, such as biodiesel, that is blended into heating oil continue to be valid. See also discussion in Section III.B.1.e.

3. Exporters

Under RFS1, exporters are assigned an RVO representing the volume of renewable fuel that has been exported, and they are required to separate all RINs that have been assigned to fuel that is exported. Since there is only one standard, there is only one possible RVO applicable to exporters.

Under RFS2, there are four possible RVOs corresponding to the four categories of renewable fuel (cellulosic biofuel, biomass-based diesel, advanced biofuel, total renewable fuel). However, given the fungible nature of the RIN system and the fact that an assigned RIN transferred with a volume of renewable fuel may not be the same RIN that was originally generated to represent that volume, there is no way for an exporter to determine from an assigned RIN which of the four categories applies to

[40] EISA, Title II, Subtitle A–Renewable Fuel Standard, Section 201.

an exported volume. In order to determine its RVOs, the only information available to the exporter is the type of renewable fuel that he is exporting.

For RFS2, we are proposing that exporters use the fuel type and its associated volume to determine his applicable RVO. To accomplish this, an exporter must know which of the four renewable fuel categories applies to a given type of renewable fuel. We are proposing that all biodiesel (mono alkyl esters) and renewable diesel would be categorized as biomass-based diesel (D code of 4), and that exported volumes of these two fuels would be used to determine the exporter's RVO for biomass-based diesel. For all other types of renewable fuel, the most likely category for most of the phase-in period of the RFS2 program is general renewable fuel, and as a result we propose that all other types of renewable fuel be used to determine the exporter's RVO for total renewable fuel. Our proposed approach is provided at § 80.1430. We recognize that by 2022 the required volume of cellulosic biofuel will exceed the required volume of general renewable fuel that is in excess of the advanced biofuel requirements. Thus we request comment on requiring all or some portion of renewable fuels other than biodiesel and renewable diesel to be categorized as cellulosic biofuel in 2022 and beyond.

An alternative approach could be required that would more closely estimate the amount of exported renewable fuels that fall into the four categories defined by EISA. In this alternative, the total nationwide volumes required in each year (*see* Table II.A.1–1) would be used to apportion specific types of renewable fuel into each of the four categories. For example, exported ethanol may have originally been produced from cellulose to meet the cellulosic biofuel requirement, from corn to meet the total renewable fuel requirement, or may have been imported as advanced biofuel. If ethanol were exported, we could divide the exported volume into three RVOs for cellulosic biofuel, advanced biofuel, and total renewable fuel using the same proportions represented by the national volume requirements for that year. However, we believe that this alternative approach would add considerable complexity to the compliance determinations for exporters without necessarily adding more precision. Given the expected small volumes of exported renewable fuel, this added complexity does not seem warranted at this time. Nevertheless, we request comment on it.

4. Alternative Approaches to RIN Transfers

In the NPRM for the RFS1 rulemaking, we presented a variety of approaches to the transfer of RINs, ultimately requiring that RINs generated by renewable fuel producers and importers must be assigned to batches of renewable fuel and transfered along with those batches. However, given the higher volumes required under RFS2 and the resulting expansion in the number of regulated parties, we believe that two of the alternative approaches to RIN transfers should be considered for RFS2. Our proposal for an EPA-moderated RIN trading system (EMTS) may also support the implementation of one of these approaches.

In one of the alternative approaches, we would entirely remove the restriction established under the RFS1 rule requiring that RINs be assigned to batches of renewable fuel and transferred with those batches. Instead, renewable fuel producers could sell RINs (with a K code of 2 rather than 1) separately from volumes of renewable fuel to any party. This approach could significantly streamline the tracking and trading of RINs. For instance, there would no longer be a need for K-codes and restrictions on separation of RINs, there would only be a single RIN market rather than two (one for RINs assigned to volume and another for separated RINs), there would be no need for volume/RIN balance calculations at the end of each quarter, and there would be no need for restrictions on the number of RINs that can be transfered with each gallon of renewable fuel. As described more fully in Section III.B.4.b.ii, this approach could also provide a greater incentive for producers to demonstrate that the renewable biomass definition has been met for their feedstocks. As discussed in Section III.G.4, this approch could help level the playing field among obligated parties for access to RINs regardless of whether they market a substantial volume of gasoline or not. However, as discussed in the RFS1 rulemaking, this approach could also place obligated parties at greater risk of market manipulation by renewable fuel producers.

In order to address some of the concerns raised about allowing producers and importers to separate RINs from their volume, in the NPRM for the RFS1 rulemaking we also presented an alternative concept for RIN distribution in which producers and importers of renewable fuels would be required to transfer the RIN, but only to an obligated party (see 71 FR 55591). This ''direct transfer'' approach would require renewable fuel producers to transfer RINs with renewable fuel for all transactions with obligated parties, and sell all other RINs directly to obligated parties on a quarterly basis for any renewable fuel volumes that were not sold directly to obligated parties. Only renewable fuel producers, importers, and obligated parties would be allowed to own RINs, and only obligated parties could take ownership of RINs from producers and importers. This approach would spare marketers and distributors of renewable fuel from the burdens associated with transferring RINs with batches, and thus would eliminate the tracking, recordkeeping and reporting requirements that would continue to be applicable to them if RINs are transferred through the distribution system as required under the RFS1 program.

Under the direct transfer alternative, the renewable fuel producer or importer would be required to transfer the RINs associated with his renewable fuel to an obligated party who purchases the renewable fuel. The RINs associated with any renewable fuel that is not directly transferred to an obligated party would not be transferred with the fuel as required under the RFS1 program. Instead, the renewable fuel producer or importer would be required to sell the RINs directly to an obligated party. Any RINs not sold in this way would be required to be offered for sale to all obligated parties through a public auction. This could be through an EPA moderated trading system, an existing internet auction web site, or through another auction mechanism implemented by a renewable fuel producer.

Although we believe that the direct transfer approach has merit, many of the concerns laid out in the RFS1 NPRM remain valid today. In particular, the auctions would need to be regulated in some way to ensure that RIN generators could not withhold RINs from the market by such means as failing to adequately advertise the time and location of an auction, by setting the selling price too high, by specifying a minimum number of bids before selling, by conducting auctions infrequently, by having unduly short bidding windows, etc. We seek comment on how we could regulate such auctions to ensure that obligated parties could acquire sufficient RINs for compliance purposes in a timely manner.

Our proposed EPA-moderated RIN trading system (see Section IV.E) could help to make the direct transfer approach feasible. By creating accounts in a centralized system within which all RIN transfers between parties would be made, it may be more straightforward for obligated parties to identify available RINs owned by producers and importers, and to bid on those RINs. Therefore, while we are not proposing the direct transfer approach in today's action, we nevertheless request comment on it.

5. Neat Renewable Fuel and Renewable Fuel Blends Designated as Transportation Fuel, Home Heating Oil, or Jet Fuel

Under RFS1, RINs must, with limited exceptions, be separated by an obligated party taking ownership of the renewable fuel, or by a party that blends renewable fuel with gasoline or diesel. In addition, a party that designates neat renewable fuel as motor vehicle fuel may separate RINs associated with that fuel if the fuel is in fact used in that manner without further blending. For purposes of the RFS program, ''neat renewable fuel'' is defined in 80.1101(p) as ''a renewable fuel to which only de minimis amounts of conventional gasoline or diesel have been added.'' One exception to these provisions is that biodiesel blends in which diesel constitutes less than 20 volume percent are ineligible for RIN separation by a blender. As noted in the preamble to the final RFS1 regulations, EPA understands that in the vast majority of cases, biodiesel is blended with diesel in concentrations of 80 volume percent or less.

However, in order to account for situations in which biodiesel blends of 81 percent or greater may be used as motor vehicle fuel without ever having been owned by an obligated party, EPA is proposing to change the applicability of the RIN separation provisions for RFS2. EPA is proposing that 80.1429(b)(4) allow for separation of RINs for neat renewable fuel or blends of renewable fuel and or diesel fuel that the party designates as transportation fuel, home heating oil, or jet fuel, provided the neat renewable fuel or blend is used in the designated form, without further blending, as transportation fuel, home heating oil, or jet fuel. As in RFS1, those parties that blend renewable fuel with gasoline or diesel fuel (in a blend containing less than 80 percent biodiesel would in all cases be required to separate RINs pursuant 80.1429(b)(2).

Thus, for example, under these proposed regulations, if a party intends to separate RINs from a volume of B85, the party must designate the blend for use as transportation fuel, home heating oil, or jet fuel and the blend must be used in its designated form without further blending. The party would also be required maintain records of this designation pursuant to 80.1451(b)(5). Finally, the party would be required to comply with the proposed PTD requirements in 80.1453(a)(5)(iv), which serve to notify downstream parties that the volume of fuel has been designated for use as transportation fuel, home heating oil, or jet fuel, and must be used in that designated form without further blending. Parties could separate RINs at the time they complied with the designation and PTD requirements, and would not need to physically track ultimate fuel use.

EPA requests comment on this proposed approach to RIN separation. Additionally, EPA requests comment on an alternative approach to modifying the current program for separation of RINs. Under this second approach, 80.1429(b)(2) and (b)(5)would be eliminated as redundant, and 80.1429(b)(4) would be broadened to require separation of RINs for all neat renewable fuels and all blends of renewable fuels with either gasoline or diesel, when a party designates such fuel as transportation fuel, home heating oil or jet fuel, and the fuel is in fact used in accordance with that designation without further blending. The party would be required to maintain records that verify the ultimate use of the fuel as transportation, home heating, or jet fuel. Additionally, there would be a PTD requirement to inform downstream parties that the fuel has been designated as transportation, home heating, or jet fuel and may not be further blended. This proposed approach would eliminate the need for parties to distinguish for purposes of separating RINs between fuels that are neat or blended or, for biodiesel, between blends of E80 and below or E81 and above.

I. Treatment of Cellulosic Biofuel

1. Cellulosic Biofuel Standard

EISA requires in section 202(e) that the Administrator set the cellulosic biofuel standard each November for the next year based on the lesser of the volume specified in the Act or the projected volume of cellulosic biofuel production for that year. In the event that the projected volume is less than the amount required in the Act, EPA may also reduce the applicable volume of the advanced biofuels requirement by the same or a lesser volume. We intend to examine EIA's projected volumes and other available data including the production outlook reports proposed in Section III.K to be submitted to the EPA to decide the appropriate standard for the following year. The outlook reports from all renewable fuel producers would assist EPA in determining what the cellulosic biofuel standard should be and if the advanced biofuel standard should be adjusted. For years where EPA determines that the projected volume of cellulosic biofuels is not sufficient to meet the levels in EISA we will consider the availability of other advanced biofuels in deciding whether to lower the advanced biofuel standard as well.

2. EPA Cellulosic Allowances for Cellulosic Biofuel

Whenever EPA sets the cellulosic biofuel standard at a level lower than that required in EISA, EPA is required to provide a number of cellulosic credits for sale that is no more than the volume used to set the standard. Congress also specified the price for such credits: adjusted for inflation, they must be offered at the price of the higher of 25 cents per gallon or the amount by which $3.00 per gallon exceeds the average wholesale price of a gallon of gasoline in the United States. The inflation adjustment will be for years after 2008. We propose that the inflation adjustment would be based on the Consumer Price Index for All Urban Consumers (CPI–U) for All Items expenditure category as provided by the Bureau of Labor Statistics.[41]

Congress afforded the Agency considerable flexibility in implementing the system of cellulosic biofuel credits. EISA states EPA; ''shall include such provisions, including limiting the credits' uses and useful life, as the Administrator deems appropriate to assist market liquidity and transparency, to provide appropriate certainty for regulated entities and renewable fuel producers, and to limit any potential misuse of cellulosic biofuel credits to reduce the use of other renewable fuels, and for such other purposes as the Administrator determines will help achieve the goals of this subsection.''

Though EISA gives EPA broad flexibility, we believe the best way to accomplish the goals of providing certainty to both the cellulosic biofuel industry and the obligated parties is to propose credits with few degrees of freedom. We believe this would prevent speculation in the market and provide certainty for investments in real cellulosic biofuels.

Specifically, we propose that the credits would be called allowances so

[41] *See* U.S. Department of Labor, Bureau of Labor Statistics (BLS), Consumer Price Index Web site at: *http://www.bls.gov/cpi/*.

that there is no confusion with RINs, such allowances would only be available for the current compliance year for which we have waived some portion of the cellulosic biofuel standard, they would only be available to obligated parties, and they would be nontransferable and nonrefundable. Further, we propose that obligated parties would only be able to purchase allowances up to the level of their cellulosic biofuel RVO less the number of cellulosic biofuel RINs that they own. This would help ensure that every party that needs to meet the cellulosic biofuel standard will have equal access to the allowances. A company would also then only use an allowance to meet its total renewable and advanced biofuel standards if it used the allowance for the cellulosic biofuel standard. We believe that if a company can only purchase as many allowances as it needs to meet its cellulosic biofuel obligation, it can not hinder another obligated party from meeting the standard and therefore every company that needs to meet the standard will have equal access to the allowances in the event that they do not acquire sufficient cellulosic biofuel RINs. If we were to allow a company to purchase more allowances than they needed, another company may not be able to meet the standard which we believe was not the intent of Congress.

We also propose that these allowances would be offered in a generic format rather than a serialized format, like RINs. Allowances would be purchased from the EPA at the time that an obligated party submits its annual compliance demonstration to the EPA and establishes that it owns insufficient cellulosic biofuel RINs to meet its cellulosic biofuel RVO. A company owning cellulosic biofuel RINs and cellulosic allowances may use both types of credits if desired to meet their RVOs, but unlike RINs they would not be able to carry allowances over to the next calendar year.

Congress refers to allowances as ''cellulosic biofuel credits,'' with no indication that the ''credits'' should be given any less role in meeting a party's obligations under the CAA section 211(o) than would the purchase and use of a cellulosic biofuel RIN that reflects actual production and use of cellulosic biofuel. Because cellulosic biofuel RINs can be used to meet the advanced biofuel and total renewable fuel standards in addition to the cellulosic biofuel standard, we propose that cellulosic biofuel allowances also be available for use in meeting those three standards.

We propose that the wholesale price of gasoline will be based on the average monthly bulk (refinery gate) price of gasoline using data from the most recent twelve months of data from EIA's annual cellulosic ethanol forecast each October.[42] Thus we will set the allowance price for the following year each November along with the cellulosic biofuel standard for the following year. We seek comment on using the average monthly rack (terminal) price for the same period and changing the allowance price as often as quarterly. Though EISA allows EPA to change the price as often as quarterly we believe this will lead to speculation which may introduce more uncertainty for the obligated parties and the cellulosic biofuel industry.

3. Potential Adverse Impacts of Allowances

While the credit provisions of section 202(e) of EISA ensure that there is a predictable upper limit to the price that cellulosic biofuel producers can charge for a gallon of cellulosic biofuel and its assigned RIN, there may be circumstances in which this provision has other unintended impacts. For instance, if we made all cellulosic allowances available to any obligated party, one obligated party could purchase more allowances than he needs to meet his cellulosic biofuel RVO and then sell the remaining allowances at an inflated price to other obligated parties. Thus, we are proposing that each obligated party could only purchase allowances from the EPA up to the level of their cellulosic biofuel RVO. However, even with this restriction an obligated party could still purchase both cellulosic biofuel volume with its assigned RINs sufficient to meet its cellulosic biofuel RVO, and also purchase allowances from the EPA. In this case, the obligated party would effectively be using allowances as a replacement for corn ethanol rather than cellulosic biofuel. To prevent this, we are proposing an additional restriction: an obligated party could only purchase allowances from the EPA to the degree that it establishes it owns insufficient cellulosic biofuel RINs to meet its cellulosic biofuel RVO. This approach forces obligated parties to apply all their cellulosic biofuel RINs to their cellulosic biofuel RVO before appying any allowances to their cellulosic biofuel RVO.

[42] More information on wholesale gasoline prices can be found on the Department of Energy's (DOE), Energy Information Administration's (EIA) Web site at: *http://tonto.eia.doe.gov/dnav/pet/pet_pri_allmg_d_nus_PBS_cpgal_m.htm*.

However, even with these proposed restrictions on the purchase and application of allowances, the statutory provision may not operate as intended. For instance, if the combination of cellulosic biofuel volume price and RIN price is low compared to that for corn-ethanol, a small number of obligated parties could purchase more cellulosic biofuel than they need to meet their cellulosic biofuel RVOs and could use the additional cellulosic biofuel RINs to meet their advanced biofuel and total renewable fuel RVOs. Other obligated parties would then have no access to cellulosic biofuel volume nor cellulosic biofuel RINs, and would be forced to purchase allowances from the EPA. This situation would have the net effect of allowances replacing imported sugarcane ethanol and/or corn-ethanol rather than cellulosic biofuel.

Moreover, under certain conditions it may be possible for the market price of corn-ethanol RINs to be significantly higher than the market price of cellulosic biofuel RINs, as the latter is limited in the market by the price of EPA-generated allowances according to the statutory formula described in Section III.I.2 above. Under some conditions, this could result in a competitive disadvantage for cellulosic biofuel in comparison to corn ethanol. For instance, if gasoline prices at the pump are significantly higher than ethanol production costs, while at the same time corn-ethanol production costs are lower than cellulosic ethanol production costs, profit margins for corn-ethanol producers would be larger than for cellulosic ethanol producers. Under these conditions, while obligated parties may still purchase cellulosic ethanol volume and its associated RIN rather than allowances, cellulosic ethanol producers would realize lower profits than corn-ethanol producers due to the upper limit placed on the price of cellulosic biofuel RINs through the pricing formula for allowances. For a newly forming and growing cellulosic biofuel industry, this competitive disadvantage could make it more difficult for investors to secure funding for new projects, threatening the ability of the industry to reach the statutorily mandated volumes.

We have not established the likelihood that these circumstances would arise in practice, and we request comment on the specific market conditions that could lead to them. Nevertheless, we have explored a variety of ways that we could modify the RFS program structure to mitigate these potential negative outcomes. For instance, as mentioned in Section III.I.2 above, we are proposing that each cellulosic allowance could be used to meet an obligated party's RVOs for cellulosic biofuel, advanced biofuel, and total renewable fuel. However, we could restrict the applicability of allowances to only the cellulosic biofuel RVO. This approach could help ensure that demand for imported sugarcane ethanol and corn ethanol does not fall in the event that a small number of obligated parties purchase all available cellulosic biofuel volume, compelling the remaining obligated parties to purchase allowances. However, this approach could also have the effect of making the advanced biofuel and total renewable fuel standards more stringent. This could occur as obligated parties are forced to buy additional imported sugarcane ethanol and corn ethanol to make up for the fact that the allowances they purchase from the EPA would not apply to the advanced biofuel and total renewable fuel standards.

As a variation to this approach, while still restricting the applicability of allowances to only the cellulosic biofuel RVO, we could similarly make cellulosic biofuel RINs applicable to only the cellulosic biofuel RVO. This approach would ensure that the compliance value of both cellulosic biofuel RINs and allowances is the same, but would necessarily result in an increase in the effective stringency of the advanced biofuel and total renewable fuel standards.

Finally, we could institute a ''dual RIN'' approach to cellulosic biofuel that has the potential to address some of the shortcomings of the previous approaches. In this approach, both cellulosic biofuel RINs (with a D code of 1) and allowances could only be applied to an obligated party's cellulosic biofuel RVO, but producers of cellulosic biofuel would also generate an additional RIN representing advanced biofuel (with a D code of 3). The producer would only be required to transfer the advanced biofuel RIN with a batch of cellulosic biofuel, and could retain the cellulosic biofuel RIN for separate sale to any party.[43] The cellulosic biofuel and its attached advanced biofuel RIN would then compete directly with other advanced biofuel and its attached advanced biofuel RIN, while the separate cellulosic biofuel RIN would have an independent market value that would be effectively limited by the pricing formula for allowances as described in Section III.I.2. However, this approach would be a more significant deviation from the RIN generation and transfer program structure that was developed cooperatively with stakeholders during RFS1. It would provide cellulosic biofuel producers with significantly more control over the sale and price of cellulosic biofuel RINs, which was one of the primary concerns of obligated parties during the development of RFS1.

[43] The cellulosic biofuel RIN would be a separated RIN with a K code of 2 immediately upon generation.

Due to the drawbacks of each of these potential changes to the RFS program structure, we are not proposing any of them in today's NPRM. However, we request comment on whether any of them, or alternatives, could address the adverse situations described above. We also request comment on the degree to which the adverse situations are likely to occur, and the degree of severity of the negative impacts that could result.

J. Changes to Recordkeeping and Reporting Requirements

1. Recordkeeping

As with the existing renewable fuel standard program, recordkeeping under this proposed program will support the enforcement of the use of RINs for compliance purposes. As with the existing renewable fuels program, we are proposing that parties be afforded significant freedom with regard to the form that product transfer documents (PTDs) take. We propose to permit the use of product codes as long as they are understood by all parties. We propose that product codes may not be used for transfers to truck carriers or to retailers or wholesale purchaser-consumers. We propose that parties must keep copies of all PTDs they generate and receive, as well as copies of all reports submitted to EPA and all records related to the sale, purchase, brokering or transfer or RINs, for five (5) years. We also propose that parties must also keep copies of records that relate to flexibilities, as described in Section IV.A. through C. of this preamble. Such flexibilities are related to attest engagements, the upward delegation of RIN-separating responsibilities, and various small business oriented provisions. Upon request, parties would be responsible for providing their records to the Administrator or the Administrator's authorized representative. We would reserve the right to request to receive documents in a format that we can read and use.

In Section IV.E. of this preamble, we propose an EPA-Moderated Trading System for RINs. If adopted, the new system would allow for real-time reporting of RIN generation (i.e., batch reports by producers and importers) and RIN transactions.

2. Reporting

Under the existing renewable fuels program, obligated parties, exporters of renewable fuel, producers and importers of renewable fuels, and any party who owns RINs must report appropriate information to EPA on a quarterly and/or annual basis. We are proposing a change in the schedule for submission of producers' and importers' batch reports, and for the submission of RIN transaction reports. This proposed change in schedule, which is discussed in great detail in Section IV.E. of this preamble, is effective for 2010 only. We are proposing that, for 2010, these reports (which were submitted quarterly under RFS1) be submitted monthly rather than quarterly. The reason for proposing monthly reporting for 2010 is to minimize difficulties associated with invalid RINs, while the EPA-Moderated Trading System is still under development. As described in detail in IV.E. we intend to have an EPA-Moderated Trading System fully operational by 2011. At the time that system becomes fully operational, all batch and RIN transactional reporting would be submitted in real time. The following deadlines would apply to ''real time,' monthly, quarterly, and annual reports.

''Real time'' reports within the EPA-Moderating Trading System would be submitted within three (3) business days of a reportable event (e.g. generation of a RIN, a transaction occurring involving a RIN). Real time reporting would apply to batch reports submitted by producers and importers who generate RINs and to to RIN transaction reports submitted in 2011 and future years.

Monthly reports would be submitted according to the following schedule:

TABLE III.J.2–1—MONTHLY REPORTING SCHEDULE

Month covered by report	Due date for report
January	February 28.
February	March 31.
March	April 30.
April	May 31.
May	June 30.
June	July 31.
July	August 31.
August	September 30.
September	October 31.
October	November 30.
November	December 31.
December	January 31.

The monthly reporting schedule would apply to batch reports submitted by producers and importers who generate RINs and to RIN transaction reports submitted for 2010 only.

Quarterly reports would be submitted on the following schedule:

TABLE III.J.–2—QUARTERLY REPORTING SCHEDULE

Quarter covered by report	Due date for report
January–March	May 31.
April–June	August 31.
July–September	November 30.
October–December	February 28.

Quarterly reports include summary reports related to RIN activities.

Annual reports (covering January through December) would continue to be due on February 28. Annual reports include compliance demonstrations by obligated parties.

Under this proposed rule, the universe of reporting parties would grow, but we propose similar reporting to existing reporting. We believe that the proposed EPA-Moderating Trading System will make reporting easier for most parties. Existing reporting forms and instructions are posted at *http://www.epa.gov/otaq/regs/fuels/rfsforms.htm*. You may wish to refer to these existing forms in preparing your comments on this proposal.

Simplified, secure reporting is currently available through our Central Data Exchange (CDX). CDX permits us to accept reports that are electronically signed and certified by the submitter in a secure and robustly encrypted fashion. Using CDX eliminates the need for wet ink signatures and reduces the reporting burden on regulated parties. It is our intention to continue to encourage the use of CDX for reporting under this proposed program as well.

Due to the criteria that renewable fuel producers and importers must meet in order to generate RINs under RFS2, and due to the fact that renewable fuel producers and importers must have documentation about whether their feedstock(s) meets the definition of ''renewable biomass,'' we propose several changes to the RFS1 RIN generation report. We propose to make the report a more general report on renewable fuel production in order to capture information on all batches of renewable fuel, whether or not RINs are generated for them. All renewable fuel producers and importers above 10,000 gallons per year would report to EPA on each batch of their fuel and indicate whether or not RINs are generated for the batch. If RINs are generated, the producer or importer would be required to certify that his feedstock meets the definition of ''renewable biomass.'' If RINs are not generated, the producer or importer would be required to state the reason for not generating RINs, such as they have documentation that states that their feedstock did not meet the definition of ''renewable biomass,'' or the fuel pathway used to produce the fuel was such that the fuel did not qualify for any D code (see Section III.B.4.b for a discussion about demonstrating whether or not feedstock meets the definition of ''renewable biomass''). For each batch of renewable fuel produced, we also propose to require information about the types and volumes of feedstock used and the types and volumes of co-products produced, as well as information about the process or processes used. This information is necessary to confirm that the producer or importer assigned the appropriate D code to their fuel and that the D code was consistent with their registration information.

Two minor additions are being incorporated into the RIN transaction report. First, for reports of RINs assigned to a volume of renewable fuel, we are asking that the volume of renewable fuel be reported. Additionally, we propose that RIN price information be submitted for transactions involving both separated RINs and RINs assigned to a renewable volume. This information is not collected under RFS1, but we believe this information has great programmatic value to EPA because it may help us to anticipate and appropriately react to market disruptions and other compliance challenges, will be beneficial when setting future renewable standards, and will provide additional insight into the market when assessing potential waivers. We anticipate that having current market information such as total number of RINs produced and RINs available in the separated market is incomplete. Missing is our ability to assess the general health and direction of the market and overall liquidity of RINs. Tracking price trend information will allow us to identify market inefficiencies and perceptions of RIN supply. When price information is combined with information from the production outlook reports, we will be better able to judge realistic expectations of renewable production and be in a better position when setting and justifying future renewable standards or pursuing relief through waiver provisions. Also, we believe the addition of price information will be highly beneficial to regulated parties. With price information being noted on transaction reports, buyers and sellers will have an additional and immediate reference when confirming transactions. Additionally, we believe that highly summarized price information (e.g., the average price of RINs traded) should be available to regulated parties, as well, and may help them to anticipate and avoid market disruptions.

We also propose to make minor changes to compliance reports related to the identification of types of RINs. Please refer to Section III.B. of this preamble for a discussion of types of renewable fuels. Also, please refer to Section III.A. for a discussion of proposed changes to RINs.

Under our proposed EPA-Moderated Trading System described in Section IV.E. of this preamble, then there would be a change in reporting burden on regulated parties that affects the frequency of reporting and the number of reports. Instead of quarterly and/or annual contact with EPA, there would be real time contact—i.e., as batches of renewable fuel are generated or as RINs are transacted. However, we believe that any burden is offset by the advantage of having a simplified system for RIN management that will promote the integrity of RINs and will remove ''guesswork'' now associated with RIN management. As things are now, a regulated party may experience frustration and incur expense in trying to track down and correct errors. Once an error is made, it propagates throughout the distribution system with each transfer from party to party. By having EPA moderate RIN management, we believe that errors would be minimized and regulated parties would be freed of the greater burden to attempt to track down and correct errors they may have made. Implementation of the EPA-Moderated Trading System would correspond to real-time reporting of the type of information contained in the following two quarterly reports: The Renewable Fuel Production Report, known as the RIN Generation Report or ''batch report'' under RFS1 (Report Form Template RFS0400), and the RIN Transaction Report (Report Form Template RFS0200), starting in 2011. For 2010, we are proposing that the type of information contained in these two forms be submitted monthly. These and other reports and instructions related to the existing renewable fuel standard program (RFS1) are posted at *http://www.epa.gov/otaq/regs/fuels/rfsforms.htm*.

3. Additional Requirements for Producers of Renewable Natural Gas, Electricity, and Propane

In addition to the general reporting requirement listed above, we are proposing an additional item of reporting for producers of renewable natural gas, electricity, and propane who choose to generate and assign RINs. While producers of renewable natural gas, electricity, and propane who generate and assign RINs would be responsible for filing the same reports as other producers of RIN-generating renewable fuels, we propose that additional reporting for these producers be required to support the actual use of their products in the transportation sector. We believe that one simple way to achieve this may be to add a requirement that producers of renewable natural gas, electricity, and propane add the name of the purchaser (e.g., the name of the wholesale purchaser-consumer (WPC) or fleet) to their quarterly RIN generation reports and then maintain appropriate records that further identify the purchaser and the details of the transaction. We are not proposing that a purchaser who is either a WPC or an end user would have to register under this scenario, unless that party engages in other activities requiring registration under this program.

K. Production Outlook Reports

We are also proposing additional reporting—annual production outlook reports that would be required of all domestic renewable fuel producers, foreign renewable fuel producers who register to generate RINs, and importers of covered renewable fuels starting in 2010. These production outlook reports would be similar to the pre-compliance reports required under the Highway and Nonroad Diesel programs. These reports would contain information about existing and planned production capacity, long-range plans, and feedstocks and production processes to be used at each production facility. For expanded production capacity that is planned or underway at each existing facility, or new production facilities that are planned or underway, the progress reports would require information on: (1) Strategic planning; (2) Planning and front-end engineering; (3) Detailed engineering and permitting; (4) Procurement and Construction; and (5) Commissioning and startup. These five project phases are described in EPA's June 2002 Highway Diesel Progress Review report (EPA document number EPA420–R–02–016, located at: *www.epa.gov/otaq/regs/hd2007/420r02016.pdf*).

The full list of requirements for the proposed production outlook reports is provided in the proposed regulations at § 80.1449. The information submitted in the reports would be used to evaluate the progress that the industry is making towards the renewable fuels volume goals mandated by EISA and to set the annual cellulosic biofuel, advanced biofuel, biomass-based diesel, and total renewable fuel standards (*see* Section II.A.7 of this preamble). We are proposing that the annual production outlook reports be due annually by February 28, beginning in 2010 and continuing through 2022, and we are proposing that each annual report must provide projected information through calendar year 2022.

EPA currently receives data on projected flexible-fuel vehicle (FFV) sales and conversions from vehicle manufacturers; however, we do not have information on renewable fuels in the distribution system. Thus, EPA is also considering whether to require the annual submission of data to facilitate our evaluation of the ability of the distribution system to deliver the projected volumes of biofuels to petroleum terminals that are needed to meet the RFS2 standards. We request comment on the extent to which such information is already publicly available or can be purchased from a proprietary source. We further request comment on the extent to which such publicly available or purchasable data would be sufficient for EPA to make its determination. To the extent that additional data might be needed, we request comment on the parties that should be required to report to EPA and what data should be required. For example, would it be appropriate to require terminal operators to report to EPA annually on their ability to receive, store, and blend biofuels into petroleum-based fuels? We believe that publicly available information on E85 refueling facilities is sufficient for us to make a determination about the adequacy of such facilities to support the projected volumes of E85 that would be used to satisfy the RFS2 standards.

We request comment on the proposed requirement of annual production outlook reports, and all other aspects mentioned above (e.g., reporting requirements, reporting dates, etc.).

L. What Acts Are Prohibited and Who Is Liable for Violations?

The prohibition and liability provisions applicable to the proposed RFS2 program would be similar to those of the RFS1 program and other gasoline programs. The proposed rule identifies certain prohibited acts, such as a failure to acquire sufficient RINs to meet a party's RVOs, producing or importing a renewable fuel that is not assigned a proper RIN category (or D Code), improperly assigning RINs to renewable fuel that was not produced with renewable biomass, failing to assign RINs to qualifying fuel, or creating or transferring invalid RINs. Any person subject to a prohibition would be held liable for violating that prohibition. Thus, for example, an obligated party would be liable if the party failed to acquire sufficient RINs to meet its RVO. A party who produces or imports renewable fuels would be liable for a failure to assign proper RINs to qualifying batches of renewable fuel produced or imported. Any party, including an obligated party, would be liable for transferring a RIN that was not properly identified.

In addition, any person who is subject to an affirmative requirement under this program would be liable for a failure to comply with the requirement. For example, an obligated party would be liable for a failure to comply with the annual compliance reporting requirements. A renewable fuel producer or importer would be liable for a failure to comply with the applicable batch reporting requirements. Any party subject to recordkeeping or product transfer document (PTD) requirements would be liable for a failure to comply with these requirements. Like other EPA fuels programs, the proposed rule provides that a party who causes another party to violate a prohibition or fail to comply with a requirement may be found liable for the violation.

EPAct amended the penalty and injunction provisions in section 211(d) of the Clean Air Act to apply to violations of the renewable fuels requirements in section 211(o). Accordingly, under the proposed rule, any person who violates any prohibition or requirement of the RFS2 program may be subject to civil penalties of $32,500 for every day of each such violation and the amount of economic benefit or savings resulting from the violation. Under the proposed rule, a failure to acquire sufficient RINs to meet a party's renewable fuels obligation would constitute a separate day of violation for each day the violation occurred during the annual averaging period.

As discussed above, the regulations would prohibit any party from creating or transferring invalid RINs. These invalid RIN provisions apply regardless of the good faith belief of a party that the RINs are valid. These enforcement provisions are necessary to ensure the RFS2 program goals are not compromised by illegal conduct in the creation and transfer of RINs.

As in other motor vehicle fuel credit programs, the regulations would address the consequences if an obligated party was found to have used invalid RINs to demonstrate compliance with its RVO.

In this situation, the obligated party that used the invalid RINs would be required to deduct any invalid RINs from its compliance calculations. Obligated parties would be liable for violating the standard if the remaining number of valid RINs was insufficient to meet its RVO, and the obligated party might be subject to monetary penalties if it used invalid RINs in its compliance demonstration. In determining what penalty is appropriate, if any, we would consider a number of factors, including whether the obligated party did in fact procure sufficient valid RINs to cover the deficit created by the invalid RINs, and whether the purchaser was indeed a good faith purchaser based on an investigation of the RIN transfer. A penalty might include both the economic benefit of using invalid RINs and/or a gravity component.

Although an obligated party would be liable under our proposed program for a violation if it used invalid RINs for compliance purposes, we would normally look first to the generator or seller of the invalid RINs both for payment of penalty and to procure sufficient valid RINs to offset the invalid RINs. However, if, for example, that party was out of business, then attention would turn to the obligated party who would have to obtain sufficient valid RINs to offset the invalid RINs.

We request comment on the need for additional prohibition and liability provisions specific to the proposed RFS 2 program.

IV. What Other Program Changes Have We Considered?

In addition to the regulatory changes we are proposing today in response to EISA that are designed to implement the provisions of RFS2, there are a number of other changes to the RFS program that we are considering. These changes would be designed to increase flexibility, simplify compliance, or address RIN transfer issues that have arisen since the start of the RFS1 program. We have also investigated impacts on small businesses and are proposing approaches designed to address the impacts of the program on them.

A. Attest Engagements

The purpose of an attest engagement is to receive third party verification of information reported to EPA. An attest engagement, which is similar to a financial audit, is conducted by a Certified Public Accountant (CPA) or Certified Independent Auditor (CIA) following agreed-upon procedures. Under the RFS1 program, an attest engagement must be conducted annually. We propose to apply the same provision to this proposed RFS2 rule. However, we seek comment on whether there should be any flexibility provisions for those who own a small number of RINs and what level of flexibility might be appropriate (e.g., allowing those who own a small number of RINs to submit an attest engagement every two years, rather than every year).

B. Small Refinery and Small Refiner Flexibilities

1. Small Refinery Temporary Exemption

CAA section 211(o)(8), enacted as part of EPAct, provides a temporary exemption to small refineries (those refineries with a crude throughput of no more than 75,000 barrels of crude per day, as defined in section 211(o)(1)(K)) through December 31, 2010.[44] Accordingly, the RFS1 program regulations exempt gasoline produced by small refineries from the renewable fuels standard (unless the exemption was waived), see 40 CFR 80.1141. EISA did not alter the small refinery exemption in any way. Therefore, we intend to retain this small refinery temporary exemption in the RFS2 program without change. Further, as discussed below in Section IV.B.2.c, we are proposing to continue one of the hardship provisions for small refineries provided at 40 CFR 80.1141(e).

2. Small Refiner Flexibilities

As mentioned above, EPAct granted a temporary exemption from the RFS program to small refineries through December 31, 2010. In the RFS1 final rule, we exercised our discretion under section 211(o)(3)(B) and extended this temporary exemption to the few remaining small refiners that met the Small Business Administration's (SBA) definition of a small business (1,500 employees or less company-wide) but did not meet the Congressional small refinery definition as noted above.

As explained in the discussion of our compliance with the Regulatory Flexibility Act below in Section XII.C and in the Initial Regulatory Flexibility Analysis in Chapter 7 of the draft RIA, we considered the impacts of today's proposed regulations on small businesses. Most of our analysis of small business impacts was performed as a part of the work of the Small Business Advocacy Review Panel (SBAR Panel, or ''the Panel'') convened by EPA, pursuant to the Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA). The Final Report of the Panel is available in the docket for this proposed rule. For the SBREFA process, we conducted outreach, fact-finding, and analysis of the potential impacts of our regulations on small businesses.

During the SBREFA process, small refiners informed us that they would need to rely heavily on RINs and/or make capital improvements to comply with the RFS2 requirements. These refiners raised concerns about the RIN program itself, uncertainty (with the required renewable fuel volumes, RIN availability, and cost), and the desire for a RIN system review access to RINs, and the difficulty in raising capital and competing for engineering resources to make capital improvements.

During the Panel process, EPA raised a concern regarding provisions for small refiners in the RFS2 rule; and this rule presents a very different issue than the small refinery versus small refiner concept from RFS1. This issue deals with whether or not EPA has the authority to provide a subset of small refineries (those that are operated by small refiners) with an extension of time that would be different from, and more than, the temporary exemption specified by Congress in section 211(o)(9) for small refineries (temporary exemption through December 31, 2010, with the potential for extensions of the exemption beyond this date if certain criteria are met.). In other words, the temporary exemption specified by Congress provided relief for those small refiners that are covered by the small refinery provision; EPA believes that providing these refiners with an additional exemption different from that provided by section 211(o)(9) may be inconsistent with the intent of Congress. Congress spoke directly to the relief that EPA may provide for small refineries, including those small refineries operated by small refiners, and limited it to a blanket exemption through December 31, 2010, with additional extensions if the criteria specified by Congress were met.

The Panel recommended that EPA consider the issues raised by the SERs and discussions had by the Panel itself, and that EPA should consider comments on flexibility alternatives that would help to mitigate negative impacts on small businesses to the extent allowable by the Clean Air Act. A summary of further recommendations of the Panel are discussed in Section XII.C of this preamble, and a full discussion of the regulatory alternatives discussed and recommended by the Panel can be found in the SBREFA Final Panel Report.

[44] Small refineries are also allowed to waive this exemption.

a. Extension of Existing RFS1 Temporary Exemption

As previously stated, the RFS1 program regulations provide small refiners who operate small refineries, as well as those small refiners who do not operate small refineries, with a temporary exemption from the standards through December 31, 2010. Small refiner SERs suggested that an additional temporary exemption for the RFS2 program would be beneficial to them in meeting the RFS2 standards; and the Panel recommended that EPA propose a delay in the effective date of the standards until 2014 for small entities, to the maximum extent allowed by the statute.

We have evaluated an additional temporary exemption for small refiners for the required RFS2 standards, and we have also evaluated such an exemption with respect to our concerns about our authority to provide an extension of the temporary exemption for small refineries that is different from that provided in CAA section 211(o)(9). As a result, we believe that the limitations of the statute do not necessarily allow us the discretion to provide an exemption for small refiners only (i.e., small refiners but not small refineries) beyond that provided in section 211(o)(9). However, it is important to recognize that the 211(o)(9) small refinery provision does allow for extensions beyond December 31, 2010, with two separate provisions addressing extensions beyond 2010. These provisions are discussed below in Section IV.B.2.c.

Therefore, we are proposing to continue the temporary exemption finalized in RFS1—through December 31, 2010—for small refineries and all qualified small refiners. We also request comment on the interpretation of our authority under the CAA and the appropriateness of providing an extension to small refiners only beyond that authorized by section 211(o)(9).

b. Program Review

During the SBREFA process, the small refiner SERs also requested that EPA perform an annual program review, to begin one year before small refiners are required to comply with the program. We have slight concerns that such a review could lead to some redundancy since EPA is required to publish a notice of the applicable RFS standards in the Federal Register annually, and this annual process will inevitably include an evaluation of the projected availability of renewable fuels. Nevertheless, some Panel members commented that they believe a program review could be beneficial to small entities in providing them some insight to the RFS program's progress and alleviate some uncertainty regarding the RIN system. As we will be publishing a Federal Register notice annually, the Panel recommended that we include an update of RIN system progress (e.g., RIN trading, publicly-available information RIN availability, etc.) in this annual notice.

We propose to include elements of RIN system progress—such as RIN trading and availability—in the annual Federal Register RFS2 standards notice. We also invite comment on additional elements to include in this review.

c. Extensions of the Temporary Exemption Based on Disproportionate Economic Hardship

As noted above, there are two provisions in section 211(o)(9) that allow for an extension of the temporary exemption beyond December 31, 2010. One involves a study by the Department of Energy (DOE) concerning whether compliance with the renewable fuel requirements would impose disproportionate economic hardship on small refineries, and would grant an extension of at least two years for a small refinery that DOE determines would be subject to such disproportionate hardship. Another provision authorizes EPA to grant an extension for a small refinery based upon disproportionate economic hardship, on a case-by-case basis.

We believe that these avenues of relief can and should be fully explored by small refiners who are covered by the small refinery provision. In addition, we believe that it is appropriate to consider allowing petitions to EPA for an extension of the temporary exemption based on disproportionate economic hardship for those small refiners who are not covered by the small refinery provision (again, per our discretion under section 211(o)(3)(B)); this would ensure that all small refiners have the same relief available to them as small refineries do. Thus, we are proposing a hardship provision for small refineries in the RFS2 program, that any small refinery may apply for a case-by-case hardship at any time on the basis of disproportionate economic hardship per CAA section 211(o)(9)(B). While EISA stated (per section 211(o)(9)(A)(ii)(I)) that the small refinery temporary exemption shall be extended for at least two years for any small refinery that the DOE small refinery study determines would face disproportionate economic hardship in meeting the requirements of the RFS2 program, we are not proposing this hardship provision given the outcome of the DOE small refinery study (as discussed below).

In the small refinery study, ''EPACT 2005 Section 1501 Small Refineries Exemption Study'', DOE's finding was that there is no reason to believe that any small refinery would be disproportionately harmed by inclusion in the proposed RFS2 program. This finding was based on the fact that there appeared to be no shortage of RINs available under RFS1, and EISA has provided flexibility through waiver authority (per section 211(o)(7)). Further, in the case of the cellulosic biofuel standard, cellulosic biofuel allowances can be provided from EPA at prices established in EISA (see proposed regulation section 80.1455). DOE thus determined that no small refinery would be subject to disproportionate economic hardship under the proposed RFS2 program, and that the small refinery exemption should not be extended beyond December 31, 2010. DOE noted in the study that, if circumstances were to change and/or the RIN market were to become non-competitive or illiquid, individual small refineries have the ability to petition EPA for an extension of their small refinery exemption (as proposed at draft regulation section 80.1441). We note that the findings of DOE's small refinery study, and a consideration of EPA's ongoing review of the functioning of the RIN market, could factor into the basis for approval of such a hardship request.

We are also proposing a case-by-case hardship provision for those small refiners that do not operate small refineries, at draft regulation section 80.1442(h), using our discretion under CAA section 211(o)(3)(B). This proposed provision would allow those small refiners that do not operate small refineries to apply for the same kind of extension as a small refinery. In evaluating applications for this proposed hardship provision, it was recommended by the SBAR Panel that EPA take into consideration information gathered from annual reports and RIN system progress updates.

d. Phase-in

The small refiner SERs suggested that a phase-in of the obligations applicable to small refiners would be beneficial for compliance, such that small refiners would comply by gradually meeting the standards on an incremental basis over a period of time, after which point they would comply fully with the RFS2 standards, however we have concerns about our authority under the statute to allow for such a phase-in of the standards. CAA section 211(o)(3)(B) states that the renewable fuel obligation shall ''consist of a single applicable percentage that applies to all categories of persons specified'' as obligated parties. This kind of phase-in approach would result in different applicable percentages being applied to different obligated parties. Further, as discussed above, such a phase-in approach would provide more relief to small refineries operated by small refiners than that provided under the small refinery provision. We do not believe that we can use our discretion under the statute to allow for such a provision; however we invite comment on the concept of a phase-in provision for all small refiners.

e. RIN-Related Flexibilities

The small refiner SERs requested that the proposed rule contain provisions for small refiners related to the RIN system, such as flexibilities in the RIN rollover cap percentage and allowing all small refiners to use RINs interchangeably. Currently in the RFS program, up to 20% of a previous year's RINs may be ''rolled over'' and used for compliance in the following year. A provision to allow for flexibilities in the rollover cap could include a higher RIN rollover cap for small refiners for some period of time or for at least some of the four standards. While the rollover cap is the means through which we are implementing the limited credit lifetime provisions in section 211(o) of the CAA, and therefore cannot simply be eliminated, the magnitude of the cap can be modified to some extent. Thus, there could be an opportunity to provide appropriate flexibility in this area. However, given the results of the DOE small refinery study, we do not believe it would be appropriate to propose a change to the RIN rollover cap for small refiners today. However, we request comment on the concept of increasing the RIN rollover cap percentage for small refiners. We also request comment on an appropriate level of that percentage. For example, would a rollover cap of 50% for small refiners be appropriate? Or, would an intermediate value between 20% and 50%, such as 35%, be more appropriate?

The Panel recommended that we take comment on allowing RINs to be used interchangeably for small refiners, but not propose this concept because under this approach small refiners would arguably be subject to a different applicable percentage than other obligated parties. However, this concept fails to require the four different standards mandated by Congress (e.g., conventional biofuel could not be used instead of cellulosic biofuel or biomass-based diesel), and is not consistent with section 211(o) of the Clean Air Act. Thus, we are not proposing this provision in this action, however we invite comment on such an approach for small refiners.

C. Other Flexibilities

1. Upward Delegation of RIN-Separating Responsibilities

Since the start of the RFS1 program on September 1, 2007, there have been a number of instances in which a party who receives RINs with a volume of renewable fuel is required to either separate or retire those RINs, but views the recordkeeping and reporting requirements under the RFS program as an unnecessary burden. Such circumstances typically might involve a renewable fuel blender, a party that uses renewable fuel in its neat form, or a party that uses renewable fuel in a non-highway application and is therefore required to retire the RINs (under RFS1) associated with the volume. In some of these cases, the affected party may purchase and/or use only small volumes of renewable fuel and, absent the RFS program, would be subject to few if any other EPA regulations governing fuels.

This situation will become more prevalent with the RFS2 program, as EISA added diesel fuel to the RFS program. With the RFS1 rule, small blenders (generally farmers and other parties that use nonroad diesel fuel) blending small amounts of biodiesel were not covered under the rule as EPAct mandated renewable fuel blending for highway use only. EISA mandates certain amounts of renewable fuels to be blended into transportation fuels—which includes nonroad diesel fuel. Thus, parties that were not regulated under the RFS1 rule who only blend a small amount of renewable fuel (and, as mentioned above, are generally not subject to many of the EPA fuels regulations) would now be regulated by the program.

Consequently, we believe it may be appropriate, and thus we are proposing today, to permit blenders who only blend a small amount of renewable fuel to allow the party directly upstream to separate RINs on their behalf. Such a provision would be consistent with the fact that the RFS1 program already allows marketers of renewable fuels to assign more RINs to some of their sold product and no RINs to the rest of their sold product. We believe that this provision would eliminate undue burden on small parties who would otherwise not be regulated by this program. We are proposing that this provision apply to small blenders who blend and trade less than 125,000 total gallons of renewable fuel per year. We also request comment on whether or not this threshold is appropriate.

We envision that such a provision would be available to any blender who must separate RINs from a volume of renewable fuel under § 80.1429(b)(2). We also request comment on appropriate documentation to authorize this upward delegation. This could be something such as a document given to the supplier identifying the RIN separation that the supplier would perform. The document could include sufficient information to precisely identify the conditions of the authorization, such as the volume of renewable fuel in question and the number of RINs assigned to that volume. By necessity the document would need to be signed by both parties, and copies retained as records by both parties, since the supplier would then be responsible for these actions. The supplier would then be allowed to retain ownership of RINs assigned to a volume of renewable fuel when that volume is transferred, under the condition that the RINs be separated or retired concurrently with the transfer of the volume. We are proposing an annual authorization that would apply to all volumes of renewable fuel transferred between two parties for a given year (i.e., the two parties would enter into a contract stating that the supplier has RIN-separation responsibilities for all transferred volumes).

We are proposing this provision solely for the case of blenders who blend and trade less than 125,000 total gallons of renewable fuel per year. A company that blends 100,000 gallons and trades 100,000 gallons would not be able to use this provision. However, we request comment on whether authorization to delegate RIN-separation responsibilities should also be allowed for other parties as well.

2. Small Producer Exemption

Under the RFS1 program, parties who produce or import less than 10,000 gallons of renewable fuel in a year are not required to generate RINs for that volume, and are not required to register with the EPA if they do not take ownership of RINs generated by other parties. We propose to maintain this exemption under the RFS2 rule. However, we request comment on whether the 10,000 gallon threshold should be higher given that the total volume of renewable fuel mandated by EISA is considerably higher than that required by the RFS1 program, or conversely whether it should be lower given that the biomass-based diesel standard is considerably lower than the mandated volume for total renewable fuel.

D. 20% Rollover Cap

EISA does not change the language in CAA section 211(o)(5) stating that renewable fuel credits must be valid for showing compliance for 12 months as of the date of generation. As discussed in the RFS1 final rulemaking, we interpreted the statute such that credits would represent renewable fuel volumes in excess of what an obligated party needs to meet their annual compliance obligation. Given that the renewable fuel standard is an annual standard, obligated parties determine compliance shortly after the end of the year, and credits would be identified at that time. In the context of our RIN-based program, we have accomplished the statute's objective by allowing RINs to be used to show compliance for the year in which the renewable fuel was produced and its associated RIN first generated, or for the following year. RINs not used for compliance purposes in the year in which they were generated will by definition be in excess of the RINs needed by obligated parties in that year, making excess RINs equivalent to the credits referred to in section 211(o)(5). Excess RINs are valid for compliance purposes in the year following the one in which they initially came into existence. RINs not used within their valid life will thereafter cease to be valid for compliance purposes.

In the RFS1 final rulemaking, we also discussed the potential ''rollover'' of excess RINs over multiple years. This can occur in situations wherein the total number of RINs generated each year for a number of years in a row exceeds the number of RINs required under the RFS program for those years. The excess RINs generated in one year could be used to show compliance in the next year, leading to the generation of new excess RINs in the next year, causing the total number of excess RINs in the market to accumulate over multiple years despite the limit on RIN life. The rollover issue could in some circumstances undermine the ability of a limit on credit life to guarantee an ongoing market for renewable fuels.

To implement the Act's restriction on the life of credits and address the rollover issue, the RFS1 final rulemaking implemented a 20% cap on the amount of an obligated party's RVO that can be met using previous-year RINs. Thus each obligated party is required to use current-year RINs to meet at least 80% of its RVO, with a maximum of 20% being derived from previous-year RINs. Any previous-year RINs that an obligated party may have that are in excess of the 20% cap can be traded to other obligated parties that need them. If the previous-year RINs in excess of the 20% cap are not used by any obligated party for compliance, they will thereafter cease to be valid for compliance purposes.

EISA does not modify the statutory provisions regarding credit life, and the volume changes by EISA also do not change at least the possibility of large rollovers of RINs for individual obligated parties. Therefore, we propose to maintain the regulatory requirement for a 20% rollover cap under the new RFS2 program. However, under RFS2 obligated parties will have four RVOs instead of one. As a result, we are proposing that the 20% rollover cap would apply separately to all four RVOs. We do not believe it would be appropriate to apply the rollover cap to only the RVO representing total renewable fuel, leaving the other three RVOs with no rollover cap. Doing so would allow all previous-year RINs used for compliance to be those with a D code of 4, and this in turn would allow an obligated party to meet one of the nested standards, such as that for biomass-based diesel, using more than 20% previous-year RINs. This could result in significant rollover of RINs with a D code of 2, representing biomass-based diesel, and the valid life of these RINs would have no meaning in this case.

Some obligated parties have suggested that the rollover cap should be raised to a value higher than 20%, citing the need for greater flexibility in the face of significantly higher volume requirements. However, we believe that a higher value could create disruptions in the RIN market as parties with excess RINs would have a greater incentive to hold onto them rather than sell them. This would especially be a concern in years where the volume of renewable fuel available in the market is very close to the RFS requirements. Nevertheless, we request comment on whether the 20% rollover cap should be raised to a higher value.

As described in Section III.G.4, some parties have also suggested that the rollover cap should be lowered to a value lower than 20%, such as 10%. In the event of concerns about the availability of RINs, a lower rollover cap would provide a greater incentive for parties with excess RINs to sell them rather than hold onto them. However, a lower rollover cap would also reduce flexibility for many obligated parties. While we are not proposing it in today's notice, we request comment on it.

E. Concept for EPA Moderated Transaction System

1. The Need for an EPA Moderated Transaction System

In implementing RFS1, we found that the 38-digit standardized RINs have proven confusing to many parties in the distribution chain. Parties have made various errors in generating and using RINs. For example, we have seen errors wherein parties have transposed digits within the RIN. We have seen parties creating alphanumeric RINs, despite the fact that RINs are supposed to consist of all numbers. We have also seen incorrect numbering of volume start and end codes.

Once an error is made within a RIN, the error propagates throughout the distribution system. Correcting an error can require significant time and resources and involve many steps. Not only must reports to EPA be corrected, underlying records and reports reflecting RIN transactions must also be located and corrected to reflect discovery of an error. Because reporting related to RIN transactions under RFS1 is only on a quarterly basis, a RIN error may exist for several months before being discovered.

Incorrect RINs are invalid RINs. If parties in the distribution system cannot track down and correct the error made by one of them in a timely manner, then all downstream parties that trade the invalid RIN will be in violation. Because RINs are the basic unit of compliance for the RFS1 program, it is important that parties have confidence when generating and using them.

All parties in the RFS1 and the proposed RFS2 regulated community use RINs. These parties include producers of renewable fuels, obligated parties, exporters, and other owners of RINS, typically marketers of renewable fuels and blenders. (Anyone can own RINs, but those who do would be subject to registration, recordkeeping, reporting, and attest engagement requirements described in this preamble.). Currently under RFS1, all RINs are used to comply with a single standard, and in 2013 an additional cellulosic standard would have been added. Under this proposed rule, there are four standards, and RINs must be generated to identify four types of renewable fuels: cellulosic biofuel, biomass-based diesel, other advanced biofuels, and other renewable fuels (e.g., corn ethanol). (For a more detailed discussion of RINs, see Section III.A of this preamble.) In the proposed EPA Moderated Transaction System (EMTS), the four types of RINs will be managed through four types of account.

Based upon problems we observed with the use of RINs under RFS1, and considering that we will now have a more complex system including four standards instead of just one, we believe that the best way to screen RINs and conduct RIN-based transactions is through EMTS.

This section describes the proposed EMTS and options for implementing it. By implementing EMTS, we believe that we would be able to greatly reduce RIN-related errors and efficiently and accurately manage the universe of RINs. There are two aspects to our proposal for EMTS. The first aspect focuses upon creating four, generic types of RIN account. The second aspect focuses upon actually developing a ''real time'' environment for handling RIN trades.

2. How EMTS Would Work

EMTS would be a closed, EPA-managed system that provides a mechanism for screening RINs as well as a structured environment for conducting RIN transactions. ''Screening'' RINs will mean that parties would have much greater confidence that the RINs they handle are genuine. Although screening cannot remove all human error, we believe it can remove most of it.

We propose that screening and assignment of RINs be made at the logical point, i.e., the point when RINs are generated through production or importation of renewable fuel. A renewable producer would electronically submit, in ''real time,'' a batch report for the volume of renewable fuel produced or imported, as well as a list of the RINs generated and assigned. EMTS would automatically screen each batch and either reject the RINs or permit them to pass into the transaction system, into the RIN generator's account, as one of the four types of RINs. Note that under RFS1, RIN generation (batch) and RIN transaction reports are submitted quarterly. Batch reports are submitted by producers and importers quarterly and reflect how they generated and assigned RINS to batches. RIN transaction reports are submitted by all parties who engage in RIN transactions, including buying or selling RINs. Under this proposed approach for RFS2, these batch reports and RIN transaction reports would be submitted monthly for calendar year 2010. However, once EMTS is implemented in calendar year 2011, these separate periodic reports may no longer be necessary. Instead the information would be submitted as RINs are generated and assigned within EMTS.

Under RFS1, the producer or importer list RINs they generate and assign via the batch report. EPA, in turn, uses the batch report data to verify RINs generated and transacted. The report is submitted quarterly. Under RFS1, the purpose of the RIN transaction report is to document RIN transactions and to document that RINs have been sold or transferred from party to party in the distribution system. This report is also submitted quarterly. The RIN transaction report includes the following information in this report: its name, its EPA company registration number, and in some cases (where compliance is on a facility basis), its EPA facility identification number. For the quarterly reporting period, the reporting party indicates the transaction type (RIN purchase, RIN sale, expired RIN, or retired RIN), and the date of the transaction. For a RIN purchase or sale, the transaction report includes the trading partner's name and the trading partner's EPA company registration number. There is also information that may have to be submitted in the event a reporting party must report a RIN that has been retired (e.g., when a RIN has become invalid due to the spillage of the associated volume of renewable fuel). As discussed above, the shortcoming of these reports is that they are only submitted quarterly. RIN errors that affect compliance may not be discovered for many months because of the relative infrequency of reporting transactions to EPA. EMTS will assume the functionality of batch reporting and transaction reporting used by regulated parties, allowing EPA to better screen RINs and reduce or eliminate generation and transaction errors.

Under the RFS2 program, we are proposing that batch reports submitted by producers and importers and RIN transaction reports be submitted monthly rather than quarterly in the first year of the program (i.e., calendar year 2010). During 2010, we will be finishing development and testing of the EMTS. In order to minimize the hardship that undiscovered, invalid RINs may cause, we propose and seek comment on increasing the frequency of reporting and our own review of reports in order to assist the regulated community with compliance. As we develop EMTS through calendar year 2010, we intend to invite and encourage interested reporting parties to ''opt in'' to EMTS. This will serve a two-fold purpose: regulated parties may opt to gain familiarity EMTS before it becomes fully operational and we may have actual customers with which to test EMTS prior to it becoming fully operational. We believe that permitting interested parties to ''opt in'' will result in a better EMTS for all.

In the second year of the program (i.e., calendar year 2011 and forward), we anticipate fully implementing the proposed EMTS and receiving the data contained in batch and RIN transaction reports in relatively ''real time'' (i.e., as transactions occur). We propose that ''real time'' be construed as within three (3) business days of a reportable event (e.g., generation and assignment of RINs, transfer of RINs).

Parties who use EMTS would have to register with EPA in accordance with the proposed RFS2 registration program described in Section III.C of this preamble. They would also have to create an account (i.e., register) via EPA's Central Data Exchange (CDX), as we envision managing EMTS via CDX. CDX is a secure and central portal through which parties may submit compliance reports. We propose that parties must establish an account with EMTS by October 1, 2010 or 60 days prior to engaging in any transaction involving RINs, whichever is later. As discussed above, the actual items of information covered by reporting under RFS2 are nearly identical to those reported under RFS1.

Once registration occurs with EMTS, individual RIN accounts would be established and the system would manage the accounts for each individual party. The RIN accounts would correspond to the four broad types of renewable fuel. RIN accounts would be established for cellulosic biofuel, biomass-based diesel, other advanced biofuels, and other renewable fuels (including corn ethanol). One big advantage of RIN accounts is that the system would make available generic accounts for transactions involving RINs of similar type. The unique identification of the RIN would exist within EMTS, but parties engaging in RIN transactions would no longer have to worry about incorrectly recording or using 38-digit RIN numbers. As with RFS1, there is no ''good faith'' provision to RIN ownership. An underlying principle of RIN ownership is still one of ''buyer beware'' and RINs may be prohibited from use at any time if they are found to be invalid. Because of the ''buyer beware'' aspect, we intend to offer the option for a buyer to accept or reject RINs from specific RIN generators or from classes of RIN generators. Also, we propose to collect information about the price associated with RINs traded. This information is not collected under RFS1, but we believe this information has great programmatic value to EPA because it may help us to anticipate and appropriately react to market disruptions and other compliance challenges, assess and develop responses to potential waivers, and assist in setting future renewable standards. We believe that highly summarized price information (e.g., the average price of RINs traded nationwide) may be valuable to regulated parties, as well, and may help them to anticipate and avoid market disruptions.

The following is an example of how a RIN transaction might occur in the proposed EMTS model:

1. Seller logs into EMTS and posts his sale of 10,000 RINs to Buyer. For this example, assume the RINs were generated in 2008 and were assigned to 10,000 gallons of ''other renewable fuel'' (corn ethanol). Seller's RIN account for ''other renewable fuel'' is automatically reduced by 10,000 with the posting of his sale to Buyer. Buyer receives automatic notification of the pending transaction.

2. Buyer logs into EMTS. She sees the sale transaction pending. Assuming it is correct, she accepts it. Upon her acceptance, her RIN account for ''other renewable fuel'' (corn ethanol) is automatically increased by 10,000 2008 assigned RINs.

3. After Seller has posted his sale and Buyer has accepted it, EMTS automatically notifies both Buyer and Seller that the transaction has been fully completed.

Under EMTS as we are proposing it, the seller would always have to initiate any transaction. The seller's account is reduced when he posts his sale. The buyer must acknowledge the sale in order to have the RINs transferred to her account. Transactions would always be limited to available RINs. Notification would automatically be sent to both the buyer and the seller upon completion of the transaction. EPA proposes to consider any sale or transfer as complete upon acknowledgement by the buyer.

We propose that RINs and the parameters of RIN generation (e.g., year) be considered public information. We also propose that summary RIN price information, such as average price of all RINs in a broad geographic area (such as a state, region, or nationwide) be considered public information. This summary price information would be aggregated from transactions conducted within EMTS, but would not be identified with individual companies or particular transactions that have occurred. Because we believe information about RIN pricing in general will be useful to regulated parties, we are proposing to make this information available to them. We propose that the actual transactions between parties and that individual company account information may be claimed as confidential business information (CBI) by the parties to that transaction. EPA would treat any information submitted that is covered by a CBI claim in accordance with the procedures at 40 CFR Part 2 and applicable Agency policies and guidelines for the handling of claimed CBI.

3. Implementation of EMTS

We anticipate that implementing EMTS will take until January 1, 2011, although we are proposing that the RFS2 program be effective on January 1, 2010. We anticipate that development of EMTS will require significant time and effort and that a delayed effective date may permit better pre-testing with interested regulated parties. We propose to permit regulated parties who are willing to participate in EMTS early to voluntarily opt-in to the system before January 1, 2011. The actual date for these parties' opt-in will depend upon the actual timeline for development of EMTS. We encourage comments from interested parties as to how we might best make use of the development period and the proposed opportunity for willing and interested parties to ''opt in'' early.

Under our proposed scenario, for the 2010 compliance year, recordkeeping and reporting would be analogous to RFS1, although registration would be enhanced in accordance with the discussion in Section III.C of this preamble and recordkeeping and reporting would reflect the four types of RIN described above. In order to avoid propagation of RIN-related errors and to prevent errors from going too long without being detected, we believe it is necessary to increase the frequency of batch reporting and RIN transaction reporting to monthly rather than quarterly during 2010.

EPA will implement the EMTS during the first year of the RFS2 program. RINs generated under the RFS1 regulations will continue to be traded and reported using the current processes. RINs would still have unique identifying information, but EMTS will allow transactions to take place on a generic basis having the system track the specific unique identifiers. We believe that EMTS will virtually eliminate errors related to tracking and using individual RINs. Parties will be required to submit RIN transactions by specifying RIN year, RIN assignment, RIN fuel type, and any other reporting requirement specified by the administrator.

Implementation of EMTS should save considerable time and resources for both industry and EPA. This is most evident considering that the proposed system virtually eliminates multiple sources of administrative errors, resulting in a reduction in costs and effort expended to correct and regenerate product transfer documents, documentation and recordkeeping, and resubmitting reports to EPA. We anticipate that a fully functioning EMTS will result in fewer reports and easier reporting for industry, and fewer reports requiring processing by EPA. Industry will need to spend less time and effort verifying the validity of the RINs they procure and allowing them to procure them on the open market with confidence. EPA will need to spend less time tracking down the responsible parties for invalid RINs. This is possible because EMTS will remove management of the 38-digit RIN from the hands of the reporting community. At the same time, EPA and the reporting community will be working with a standardized system, reducing stresses and development costs on IT systems.

In summary, the advantage to implementing EMTS is that parties may engage in RIN transactions with a high degree of confidence. Errors would be virtually eliminated. Everyone engaging in RIN transactions would have a simplified environment in which to work which should minimize the level of resources needed for implementation. However, the one unavoidable disadvantage that we foresee is that parties would have to switch to a new and different reporting system in the second year of the RFS2 program. Some errors may still occur in by parties who continue to generate and use the 38-digit RINs during 2010. As discussed above, we propose to increase the frequency of batch and RIN transaction reporting to monthly for 2010, in order that we may help parties discover errors and correct them before they become violations. We also propose to permit parties to voluntarily ''opt in'' to using EMTS while it is still in development in order to ease the transition. We invite comment from all interested parties as to how we may best assist regulated parties in transitioning from the ''old'' RFS1 method of handing RINs to the ''new,'' proposed RFS2 EMTS method on January 1, 2011.

We also invite comment on whether, in the event the RFS2 start date is delayed, EPA should nevertheless allow a one-year period during which use of EMTS is optional, or if EPA should begin the program at the inception of the delayed RFS2 program if EMTS is fully operational at that time.

F. Retail Dispenser Labelling for Gasoline With Greater Than 10 Percent Ethanol

Fuel retailers expressed concern that the magnitude of the price discount for E85 relative to E10 that would be necessary to facilitate sufficient use of E85 would encourage widespread misfueling of non-flex fuel vehicles. Today's proposal contains labeling requirements for pumps that dispense blends that contain greater than 10% ethanol which state that the use in non-flex fuel vehicles is prohibited and may cause damage to the vehicle.[45] We anticipate that the industry would also conduct public information activities to alert customers who may not have yet become accustomed to seeing E85 at retail to avoid using E85 in their non-flex-fuel vehicles. Uniquely colored/labeled nozzle handles may also be useful in helping to prevent accidental cases of misfueling. We believe that in most cases the warnings that the use of E85 in non-flex fuel vehicles is illegal, can damage the vehicle, and can void vehicle manufacturer warranties may be a sufficient disincentive to prevent intentional misfueling. In cases where intentional misfueling may occasionally take place, the party is likely to experience drivability problems and thus would not repeat the act.

Today's proposal does not contain requirements that E85 refueling hardware be configured to prevent the introduction of E85 into non-flex-fuel vehicles. It is unclear how such an approach could be implemented to allow the approximately 6 million flex-fuel vehicles on the road today to continue to be fueled with E85 without modification to their filler neck hardware.[46] In any event, we do not believe that unique E85 nozzles are necessary.

We request comment on whether the proposed labeling requirements and voluntary measures such as those described above would provide sufficient warning to fuel retail customers not to refuel non-flex-fuel vehicles with E85. To the extent that other measures to prevent misfueling are thought to be necessary, comment is requested on the specific nature of such measures and the associated potential costs and benefits. One additional potential measure to prevent misfueling would be for cards to be issued to flex fuel vehicle owners and for all E85 dispensers to be equipped with card readers that would allow E85 to be dispensed only to card holders.

V. Assessment of Renewable Fuel Production Capacity and Use

To assess the impacts of this rule, there must be a clear understanding of the kind of renewable fuels that could be used, the types and locations of their feedstocks, the fuel volumes that could be produced by a given feedstock, and any challenges associated with their use. This section provides this assessment of the potential feedstocks and renewable fuels that may be used to meet the Energy Independence and Security Act (EISA) and the rationale behind our projections of various fuel types to represent the control case for analysis purposes. Definitional issues regarding the four types of renewable fuel required under EISA are discussed in Section III.B of this preamble.

A. Summary of Projected Volumes

EISA mandates the use of increasing volumes of renewable fuel. To assess the impacts of this increase in renewable fuel volume from business-as-usual (what is likely to have occurred without EISA), we have established a reference and control case from which subsequent analyses are based. The reference case is essentially a projection of renewable fuel volumes without the enactment of EISA. The control case is a projection of the volumes and types of renewable fuel that might be used to comply with the EISA volume mandates. Both the reference and control cases are discussed in further detail below.

1. Reference Case

Our reference case renewable fuel volumes are based on the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2007 reference case projections. The AEO 2007 presents long-term projections of energy supply, demand, and prices through 2030 based on results from EIA's National Energy Modeling System (NEMS). EIA's analysis focuses primarily on a reference case (which we use as our reference case), lower and higher economic growth cases, and lower and higher energy price cases. AEO 2007 projections generally are based on Federal, State, and local laws and regulations in effect on or before October 31, 2006.[47] The potential impacts of pending or proposed legislation, regulations, and standards are not reflected in the projections. While AEO 2007 is not as up-to-date as AEO 2008 (or the recently released AEO 2009), we chose to use AEO 2007 because AEO 2008 already includes the impact of increased renewable fuel volumes under EISA as well as fuel economy improvements under CAFE, whereas AEO 2007 did not. Table V.A.1–1 summarizes the fuel types and volumes for the years 2009–2022 as taken from AEO 2007. For our air quality analysis we also considered a reference case assuming the mandated renewable fuel volumes under the Renewable Fuel Standard Program from the Energy Policy Act of 2005 (EPAct). Refer to Section VII for further details.

TABLE V.A.1–1—AEO 2007 REFERENCE CASE PROJECTED RENEWABLE FUEL VOLUMES

[billion gallons]

Year	Advanced biofuel			Non-advanced biofuel	Total renewable fuel
	Cellulosic biofuel	Biomass-based diesel[a]	Other advanced biofuel	Corn ethanol	
	Cellulosic ethanol	FAME biodiesel[b]	Imported ethanol		
2009	0.07	0.32	0.50	9.44	10.33
2010	0.12	0.32	0.29	10.49	11.22
2011	0.19	0.33	0.16	10.69	11.37
2012	0.25	0.33	0.18	10.81	11.57

[45] *See* section 80.1469 in the proposed regulatory text.

[46] An E85 nozzle design and corresponding flex-fuel vehicle filler design that would prevent the introduction of E85 into non-flex-fuel vehicles while allowing flex fuel vehicles to be fueled with E10 as well as E85 would also prevent the introduction of E85 into current flex-fuel vehicles since there is currently no difference in nozzle/filler neck hardware between flex-fuel and non-flex-fuel vehicles.

[47] EIA. Annual Energy Outlook 2007 with Projections to 2030. *http://www.eia.doe.gov/oiaf/archive/aeo07/index.html*. Accessed February 2008.

TABLE V.A.1–1—AEO 2007 REFERENCE CASE PROJECTED RENEWABLE FUEL VOLUMES—Continued

[billion gallons]

Year	Advanced biofuel			Non-advanced biofuel	Total renewable fuel
	Cellulosic biofuel	Biomass-based diesel[a]	Other advanced biofuel	Corn ethanol	
	Cellulosic ethanol	FAME biodiesel[b]	Imported ethanol		
2013	0.25	0.33	0.19	10.93	11.70
2014	0.25	0.23	0.20	11.01	11.69
2015	0.25	0.25	0.39	11.10	11.99
2016	0.25	0.35	0.51	11.16	12.27
2017	0.25	0.36	0.53	11.30	12.44
2018	0.25	0.36	0.54	11.49	12.64
2019	0.25	0.37	0.58	11.69	12.89
2020	0.25	0.37	0.60	11.83	13.05
2021	0.25	0.38	0.63	12.07	13.33
2022	0.25	0.38	0.64	12.29	13.56

[a] Biomass-Based Diesel includes FAME biodiesel, cellulosic diesel, and non-co-processed renewable diesel. AEO 2007 only projects FAME biodiesel volumes.
[b] Fatty acid methyl ester (FAME) biodiesel.

2. Control Case for Analyses

Our assessment of the renewable fuel volumes required to meet EISA necessitates establishing a primary set of fuel types and volumes on which to base our assessment of the impacts of the new standards. EISA contains four broad categories: cellulosic biofuel, biomass-based diesel, total advanced biofuel, and total renewable fuel. As these categories could be met with a wide variety of fuel choices, in order to assess the impacts of the rule, we projected a set of reasonable renewable fuel volumes based on our interpretation at the time we began our analysis of likely fuels that could come to market.

Although actual volumes and feedstocks may be different, we believe the projections made for our control case are within the range of reasonable predictions and allow for an assessment of the potential impacts of the RFS2 standards. Table V.A.2–1 summarizes the fuel types used for the control case and their corresponding volumes for the years 2009–2022.

TABLE V.A. 2–1—CONTROL CASE PROJECTED RENEWABLE FUEL VOLUMES

[billion gallons]

Year	Advanced biofuel					Non-Advanced Biofuel	Total renewable fuel
	Cellulosic biofuel	Biomass-based diesel[a]		Other advanced biofuel		Corn ethanol	
	Cellulosic ethanol	FAME[b] biodiesel	Non-co-processed renewable diesel	Co-processed renewable diesel	Imported ethanol		
2009	0.00	0.50	0.00	0.00	0.50	9.85	10.85
2010	0.10	0.64	0.01	0.01	0.29	11.55	12.60
2011	0.25	0.77	0.03	0.03	0.16	12.29	13.53
2012	0.50	0.96	0.04	0.04	0.18	12.94	14.66
2013	1.00	0.94	0.06	0.06	0.19	13.75	16.00
2014	1.75	0.93	0.07	0.07	0.36	14.40	17.58
2015	3.00	0.91	0.09	0.09	0.83	15.00	19.92
2016	4.25	0.90	0.10	0.10	1.31	15.00	21.66
2017	5.50	0.88	0.12	0.12	1.78	15.00	23.40
2018	7.00	0.87	0.13	0.13	2.25	15.00	25.38
2019	8.50	0.85	0.15	0.15	2.72	15.00	27.37
2020	10.50	0.84	0.16	0.16	2.70	15.00	29.36
2021	13.50	0.83	0.17	0.17	2.67	15.00	32.34
2022	16.00	0.81	0.19	0.19	3.14	15.00	35.33

[a] Biomass-Based Diesel includes FAME biodiesel, cellulosic diesel, and non-co-processed renewable diesel.
[b] Fatty acid methyl ester (FAME) biodiesel.

We needed to make this projection soon after EISA was signed to allow sufficient time to conduct our long lead-time analyses. As a result, we used the same ethanol-equivalence basis for these projections as was used in the RFS1 rulemaking. However, as described in Section III.D.1, we are also co-proposing that volumes of renewable fuel be counted on a straight gallon-for-gallon basis under RFS2, such that all Equivalence Values would be 1.0. The net effect of these two approaches to Equivalence Values on projected volumes is very small; instead of 36 billion gallons of renewable fuel in 2022, our control case includes 35.3 billion gallons. We do not believe that this difference will substantively affect the analyses that are based on our projected control case volumes.

The following subsections detail our rationale for projecting the amount and type of fuels needed to meet EISA as shown in Table V.A.2–1. For cellulosic biofuel we have assumed that the entire volume will be domestically produced cellulosic ethanol. Biomass-based diesel is assumed to be comprised of a majority of fatty-acid methyl ester (FAME) biodiesel and a smaller portion of non-co-processed renewable diesel. The portion of the advanced biofuel category not met from cellulosic biofuel and biomass-based diesel is assumed to come mainly from imported (sugarcane) ethanol with a smaller amount from co-processed renewable diesel. The total renewable fuel volume not required to be comprised of advanced biofuels is assumed to be met with corn ethanol.

In addition, the following subsections also describe other fuels that have the potential to contribute to meeting EISA, but because of their uncertainty of use, or because their use likely might be negligible we have chosen to not assume any use for our analysis. Examples of these types of renewable fuels or blendstocks include bio-butanol, biogas, cellulosic diesel, cellulosic gasoline, biofuel from algae, jatropha, or palm, imported cellulosic ethanol, other biomass-to-liquids (BTL), and other alcohols or ethers. We intend to revisit these assumptions for the final rule and invite comment on whether these renewable fuels or other potential fuels which have not been included in our analyses should be included.

a. Cellulosic Biofuel

As defined in EISA, cellulosic biofuel means renewable fuel produced from any cellulose, hemicellulose, or lignin that is derived from renewable biomass and that has lifecycle greenhouse gas emissions, as determined by the Administrator, that are at least 60% less than the baseline lifecycle greenhouse gas emissions.

When many people think of cellulosic biofuel, they immediately think of cellulosic ethanol. However, cellulosic biofuel could be comprised of other alcohols, synthetic gasoline, synthetic diesel fuel, and synthetic jet fuel, propane, and biogas. Whether cellulosic biofuel is ethanol will depend on a number of factors, including production costs, the form of tax subsidies, credit programs, and issues associated with blending the biofuel into the fuel pool. It will also depend on the relative demand for gasoline and diesel fuel. For instance, European refineries are undersupplying the European market with diesel fuel and oversupplying it with gasoline, and based on the recent high diesel fuel price margins over gasoline, it seems that the U.S. is falling in line with Europe. Therefore, if the U.S. trend is toward being relatively oversupplied with gasoline, there could be a price advantage towards producing renewable fuels that displace diesel fuel rather than a gasoline fuel replacement like ethanol.

Current efforts in converting cellulosic feedstocks into fuels focus on biochemical and thermochemical conversion processes. Biochemical processes use live bacteria or isolated enzymes, or acids, to break cellulose down into fermentable sugars. The advantage of using live bacteria or enzymes is that simple carbon steel could be used which helps to control the capital costs. However, bacteria and enzymes that break down cellulose are generally specific to certain types of cellulose, thus, the cellulosic biofuel facility may have difficulty processing different types of feedstocks.[48] If live bacteria are used, the bacteria could be susceptible to contamination that could force a plant shutdown. An example of a company using enzymes to process cellulose into ethanol is Iogen, which has a demonstration plant in Canada.

On the other hand, biochemical processes which rely on strong acids will likely be less susceptible to contamination issues, and could more easily process mixed feedstocks. Thus, strong acid biochemical cellulosic ethanol plants could process MSW or a variety of feedstocks which may be available in areas where no single feedstock dominates. The strong acids, however, would likely require more expensive metallurgy. A company which is planning to use strong acids to hydrolyze the cellulose is Blue Fire Ethanol. Blue Fire is planning on building a MSW plant in Southern California. Once cellulose is reduced to simple sugars, either strong acid or enzymatic cellulosic ethanol plants operate in a manner similar to a corn ethanol plant. This consists of fermenting sugars into ethanol and then separating the ethanol from the water that facilitated the fermentation step.

The thermochemical conversion process is very different from the biochemical process right from the beginning. For the thermochemical process, feedstocks are partially burned with oxygen at a very high temperature and converted into a synthesis gas comprised of carbon monoxide and hydrogen. The principal advantage of the thermochemical process is that virtually any hydrocarbon material could be processed as feedstock, as they would all be converted to the synthesis gas, even if they produce different relative concentrations of carbon monoxide and hydrogen. The synthesis gas is typically converted to ethanol or diesel by one of several different processes.

Examples of companies currently pursuing the thermochemical route to selectively produce ethanol include Range Ethanol and Coskata. Range Ethanol is using a specially formulated catalyst that will primarily produce ethanol, but it will produce other higher molecular weight alcohols as well which would be recycled and mostly converted to ethanol. Coskata, which is being supported by General Motors, is planning on using bacteria to convert the synthesis gas to ethanol.

Another thermochemical plant could employ a very similar gasification reactor, but instead of producing ethanol from syngas, a Fischer Tropsch (F–T) reactor would be used to produce a primarily diesel product, i.e., cellulosic diesel. The F–T reactor would use a specially designed iron or cobalt catalyst to convert the syngas to straight chain hydrocarbon compounds of varying lengths and molecular weights. The heavier of these hydrocarbon compounds are then hydrocracked to produce a very high percentage of valuable diesel fuel and naphtha (gasoline type compounds). The F–T diesel fuel produced from the F–T process is very high in quality due to its high cetane and essentially zero sulfur level. While the naphtha produced from the F–T process also contains essentially zero sulfur, it is very low in octane and thus is a poor gasoline blendstock (although it could still be desirable as a gasoline blendstock because of all the high octane ethanol being blended into gasoline). Cellulosic naphtha is also valuable as a cracking feedstock for producing various petrochemical compounds. Since the F–T diesel is of better quality than the naphtha, the heavier hydrocarbon compounds are selectively hydrocracked to produce more diesel over naphtha.

No commercial cellulosic diesel plants currently exist in the U.S., nor elsewhere in the world. Currently, there is a cellulosic diesel pilot plant operated by Choren in Germany and a commercial sized plant in the planning stages by Choren also in Germany. Choren is planning to employ woody materials and agricultural residue as feedstocks. Choren specially developed a three-stage gasification process for dealing with the complexities of

[48] This is currently an area of intense research.

biomass and has partnered with Shell which has commercialized a F–T reaction process. The Choren commercial cellulosic diesel plant in Germany is expected to begin operating in 2010. Although coal-to-liquids (CTL) plants rely on coal as their feedstock, they are very similar to cellulosic diesel plants in design and help to demonstrate the feasibility of the cellulosic diesel process. There are CTL pilot plants which are operating today, as well as a number of commercial CTL plants operating today or in the planning stages. Some of these plants have experimented with or are being planned for co-feeding biomass along with the coal. A current list of proposed cellulosic diesel and CTL plants is provided in Chapter 1 of the DRIA.

In terms of production costs, at least for the current state of technology, neither the biochemical nor thermochemical platforms (comparing enzymatic biochemical processing to ethanol and thermochemical processing to cellulosic diesel) appear to have clear advantages in capital costs or operating costs.[49] Other processing techniques, for example, the syngas-to-ethanol process used by Coskata, claim to be capable of producing at even lower production costs, but without any commercial facilities operating today, it is hard to predict how these other processing techniques differ from our estimates of what the production costs for cellulosic biofuel facilities will be in the future and which technology pathways will be most economic. As such, both enzymatic biochemical and thermochemical technologies could be key processing pathways for the production of cellulosic biofuel.

The economic competitiveness of cellulosic biofuels will also depend on the extent of financial support from the government. Under the Farm Bill of 2008, both cellulosic ethanol and cellulosic diesel receive the same tax subsidies ($1.01 per gallon each). The tax subsidy, however, gives ethanol producers a considerable advantage over those producing cellulosic diesel due to the feedstock quantity needed per gallon produced (i.e., typically the higher the energy content of the product, the more feedstock that is required). On an energy basis, cellulosic ethanol would receive approximately $13/mmBtu while cellulosic diesel would receive approximately $8/mmBtu. In a similar manner, if we were to finalize an approach to the Equivalence Values for generating RINs in which volume rather than energy content is the basis, there would be an advantage for the production of cellulosic ethanol over cellulosic diesel.

One large advantage that cellulosic diesel has over ethanol is the ability for the fuel to be blended easily into the current distribution infrastructure at sizeable volumes. There are currently factors tending to limit the amount of ethanol that can be blended into the fuel pool (see Section V.D. for more discussion). Thus, the production of cellulosic diesel instead of cellulosic ethanol could help increase consumption of renewable fuels.

Thus, there is uncertainty as to which mix of cellulosic biofuels will be produced to fulfill the 16 Bgal mandate by 2022. The latest release of AEO 2009, for example, estimates a mixture of cellulosic diesel and ethanol produced for cellulosic biofuel. For assessing the impacts of the RFS2 standards, we made the simplifying assumption that cellulosic biofuel would only consist of ethanol, though market realities may also result in cellulosic diesel and other products. We are requesting comment on the types of cellulosic biofuel that should be accounted for in our analyses and whether certain fuels are more likely to come to fruition than others.

Cellulosic biofuel could also be produced internationally. One example of internationally produced cellulosic biofuel is ethanol produced from bagasse or straw from sugarcane processing in Brazil. Currently, Brazil burns bagasse to produce steam and generate bioelectricity. However, improving efficiencies over the coming decade may allow an increasing portion of bagasse to be allocated to other uses, including cellulosic biofuel, as the demand for bagasse for steam and bioelectricity could remain relatively constant.

One recent study assessed the biomass feedstock potential for selected countries outside the United States and projected supply available for export or for biofuel production.[50][51] For the study's baseline projection in 2017, it was estimated that approximately 21 billion ethanol-equivalent gallons could be produced from cellulosic feedstocks at $36/dry tonne or less. The majority (~80%) projected is from bagasse, with the rest from forest products. Brazil was projected to have the most potential for cellulosic feedstock production from both bagasse and forest products. Other countries include India, China, and those belonging to the Caribbean Basin Initiative (CBI), though much smaller feedstock supplies are projected as compared to Brazil. Although international production of cellulosic biofuel is possible, it is uncertain whether this supply would be available primarily to the U.S. or whether other nations would consume the fuel domestically. Therefore, for our analyses we have chosen to assume that all the cellulosic biofuel used to comply with RFS2 would be produced domestically.

b. Biomass-Based Diesel

Biomass-based diesel as defined in EISA means renewable fuel that is biodiesel as defined in section 312(f) of the Energy Policy Act of 1992 with lifecycle greenhouse gas emissions, as determined by the Administrator, that are at least 50% less than the baseline lifecycle greenhouse gas emissions. Biomass-based diesel can include fatty acid methyl ester (FAME) biodiesel, renewable diesel (RD) that has not been co-processed with a petroleum feedstock, as well as cellulosic diesel. Although cellulosic diesel produced through the Fischer-Tropsch (F–T) process could potentially contribute to the biomass-based diesel category, we have assumed for our analyses that the fuel and its corresponding feedstocks (cellulosic biomass) are already accounted for in the cellulosic biofuel category discussed previously in Section V.A.2.a.

FAME and RD processes can make acceptable quality fuel from vegetable oils, fats, and greases, and thus will generally compete for the same feedstock pool. For our analyses, we have assumed that the volume contribution from FAME biodiesel and RD will be a function of the available feedstock types. In our analysis we assumed that virgin plant oils would be preferentially processed by biodiesel plants, while the majority of fats and greases would be routed to RD production.[52][53] This is because the RD process involves hydrotreating (or thermal depolymerization), which is more severe and uses multiple chemical mechanisms to reform the fat molecules into diesel range material. The FAME

[49] Wright, M. and Brown, R, ''Comparative Economics of Biorefineries Based on the Biochemical and Thermochemical Platforms,'' *Biofuels, Bioprod. Bioref.* 1:49–56, 2007.

[50] Countries evaluated include Argentina, Brazil, Canada, China, Colombia, India, Mexico, and CBI.

[51] Kline, K. *et al.,* ''Biofuel Feedstock Assessment for Selected Countries,'' Oak Ridge National Laboratory, February 2008.

[52] Recent changes to federal tax subsidies and market shifts may warrant changes to this assumption. We will reevaluate the relative production volumes of biodiesel and renewable diesel for the FRM.

[53] This analysis was conducted prior to the completion of our lifecycle analysis discussed in Section VI, and assumes the fuels will meet the required GHG threshold.

process, by contrast, relies on more specific chemical mechanisms and requires pre-treatment if the feedstocks contain more than trace amounts of free fatty acids or other contaminates which are typical of recycled fats and greases. In terms of volume availability of feedstocks, supplies of fats and greases are more limited than virgin vegetable oils. As a result, our control case assumes the majority of biomass-based diesel volume is met using biodiesel facilities processing vegetable oils, with RD making up a smaller portion and using solely fats and greases.

The RD production volume must be further classified as co-processed or non-co-processed, depending on whether the renewable material was mixed with petroleum during the hydrotreating operations (more details on this definition are in Section III.B.1). EISA specifically forbids co-processed RD from being counted as biomass-based diesel, but it can still count toward the total advanced biofuel requirement. What fraction of RD will ultimately be co-processed is uncertain at this time, since little or no commercial production of RD is currently underway, and little public information is available about the comparative economics and feasibility of the two methods. We assumed in our control case that half the material will be non-co-processed and thus qualify as biomass-based diesel. We invite comment on whether RD production will favor co-processing or non-co-processing with a petroleum feedstock in the future.

Perhaps the feedstock with the greatest potential for providing large volumes of oil for the production of biomass-based diesel is microalgae. Algae grown on land in photo-bioreactors or in open ponds could potentially yield 15 to 50 times more oil per acre than traditional oil crops such as soy, rapeseed, or oil palm. Additionally it can be cultivated on marginal land with low nutrient inputs, and thus does not suffer from the sheer resource constraints that make other biofuel feedstocks problematic at large scale. However, several technical hurdles do still exist. Specifically, more efficient harvesting, dewatering and lipid extraction methods are needed to lower costs to a level competitive with other biodiesel feedstocks (20–30% of current costs). Until these hurdles are overcome, it is unlikely that algae-based biodiesel can be commercially competitive with other biodiesel fuels. Thus, for our control case we have chosen not to include oil from algae as a feedstock. Although the majority of algae to biofuel companies are focusing on producing algae oil for traditional biodiesel production, several companies are alternatively using algae for producing ethanol or crude oil for gasoline or diesel which could also help contribute to the advanced biofuel mandate.[54] For more detail on algae as a feedstock refer to Section 1.1 of the DRIA.

Jatropha curcas, a shrub native to Central America, is yet another possible biofuel feedstock. The perennial yields oil-rich seeds yearly, with oil yields per acre up to 4 times that of soy and twice that of rapeseed under optimal conditions. It can grow on low-nutrient lands, and is tolerant of drought. However, jatropha yields under these marginal conditions are hard to predict because of insufficient commercial experience; it is possible that jatropha will have low yields in the sub-optimal conditions where its cultivation would be most advantageous. Furthermore, jatropha seed harvesting is very labor intensive, and little is known about the crop's sustainability impacts, its long-term yield, or the feasibility of cultivation as a monoculture. It is unlikely that jatropha can be cultivated in the United States economically or sustainably, and the possibility of importing jatropha oil or biodiesel from producing countries is very uncertain because overseas cultivation efforts are still underdeveloped and initial volumes will likely be used domestically. As a result, we have not projected the use of jatropha as a feedstock under our control case. For more detail on the potential use of jatropha refer to Section 1.1 of the DRIA.

c. Other Advanced Biofuel

As defined in EISA, advanced biofuel means renewable fuel, other than ethanol derived from corn starch, that has lifecycle greenhouse gas emissions, as determined by the Administrator, that are at least 50% less than baseline lifecycle greenhouse gas emissions. As described more fully in Section VI.D, we are proposing that the GHG threshold for advanced biofuels be adjusted to 44% or potentially as low as 40% depending on the results from the analyses that will be conducted for the final rule. As defined in EISA, advanced biofuel includes the cellulosic biofuel, biomass-based diesel, and co-processed renewable diesel categories that were mentioned in Sections V.A.2.a and V.A.2.b above. However, EISA requires greater volumes of advanced biofuel than just the volumes required of these fuels; see Table V.A.2–1. It is entirely possible that greater volumes of cellulosic biofuel, biomass-based diesel, and co-processed renewable diesel than required by EISA could be produced in the future. Our control case, however, does not assume that cellulosic biofuel and biomass-based diesel volumes will exceed those required under EISA.[55] As a result, to meet the total advanced biofuel volume required under EISA, advanced biofuel types are needed other than cellulosic biofuel, biomass-based diesel, and co-processed renewable diesel through 2022.

We have assumed for our control case that the most likely source of advanced fuel other than cellulosic biofuel, biomass-based diesel, and co-processed renewable diesel would be from imported sugarcane ethanol.[56] Our assessment of international fuel ethanol production and demand indicate that anywhere from 3.8–4.2 Bgal of sugarcane ethanol from Brazil could be available for export by 2020/2022. If this volume were to be made available to the U.S., then there would be sufficient volume to meet the advanced biofuel standard. To calculate the amount of imported ethanol needed to meet the EISA standards, we took the difference between the total advanced biofuel category and cellulosic biofuel, biomass-based diesel, and co-processed renewable diesel categories. The amount of imported ethanol required by 2022 is approximately 3.2 Bgal. We solicit comment on our estimate of 3.2 Bgal and whether or not it is reasonable to assume that Brazil (or any other country) could satisfy this demand.

Recent news indicates that there are also plans for sugarcane ethanol to be produced in the U.S in places where the sugar subsidy does not apply. For instance, sugarcane has been grown in California's Imperial Valley specifically for the purpose of making ethanol and using the cane's biomass to generate electricity to power the ethanol distillery as well as export excess electricity to the electric grid.[57] There are at least two projects being developed at this time that could result in several

[54] Algenol and Sapphire Energy, *see http://www.algenolbiofuels.com/* and *http://www.sapphireenergy.com/.*

[55] While cellulosic biofuel will not be limited by feedstock availability, it likely will be limited by the very aggressive ramp up in production volume for an industry which is still being demonstrated on the pilot scale and therefore is not yet commercially viable. On the other hand, biomass-based diesel derived from agricultural oils and animal fats are faced with relatively high feedstock costs which limit feedstock supply.

[56] This analysis was conducted prior to the completion of our lifecycle analysis discussed in Section VI, and assumes the fuel will meet the required GHG threshold.

[57] Personal communication with Nathalie Hoffman, Managing Member of California Renewable Energies, LLC, August 27, 2008.

hundred million gallons of ethanol produced. The sugarcane is being grown on marginal and existing cropland that is unsuitable for food crops and will replace forage crops like alfalfa, Bermuda grass, Klein grass, etc. Harvesting is expected to be fully mechanized. Thus, there is potential for these projects and perhaps others to help contribute to the EISA biofuels mandate. This could lower the volume needed to be imported from Brazil.

Butanol is another potential motor vehicle fuel which could be produced from biomass and used in lieu of ethanol to comply with the RFS2 standard. Production of butanol is being pursued by a number of companies including a partnership between BP and Dupont. Other companies which have expressed the intent to produce biobutanol are Baer Biofuels and Gevo. The near term technology being pursued for producing butanol involves fermentation of starch compounds, although it can also be produced from cellulose. Butanol has several inherent advantages compared to ethanol. First, it has higher energy density than ethanol which would improve fuel economy (mpg). Second, butanol is much less water soluble which may allow the butanol to be blended in at the refinery and the resulting butanol-gasoline blend then more easily shipped through pipelines. This would reduce distribution costs associated with ethanol's need to be shipped separately from its gasoline blendstock and also save on the blending costs incurred at the terminal. Third, butanol can be blended in higher concentrations than 10% which would likely allow butanol to be blended with gasoline at high enough concentrations to avoid the need for most or all of high concentration ethanol-gasoline blends, such as E85, that require the use of fuel flexible vehicles. For example, because of butanol's lower oxygen content, it can be blended at 16% (by volume) to match the oxygen concentration of ethanol blended at 10% (by volume).[58] Because of butanol's higher energy density, when blending butanol at 16% by volume, it is the renewable fuels equivalent to blending ethanol at about 20 percent. Thus, butanol would enable achieving most of the RFS2 standard by blending a lower concentration of renewable fuel than having to resort to a sizable volume of E85 as in the case of ethanol. As pointed out in Section V.D., the need to blend ethanol as E85 provides some difficult challenges. The use of butanol may be one means of avoiding these blending difficulties.

At the same time, butanol has a couple of less desirable aspects relative to ethanol. First, butanol is lower in octane compared to ethanol—ethanol has a very high blending octane of around 115, while butanol's octane ranges from 87 octane numbers for normal butanol and 94 octane numbers for isobutanol. Potential butanol producers are likely to pursue producing isobutanol over normal butanol because of isobutanol's higher octane content. Higher octane is a valuable attribute of any gasoline blendstock because it helps to reduce refining costs. A second negative property of butanol is that it has a much higher viscosity compared to either gasoline or ethanol. High viscosity makes a fuel harder to pump, and more difficult to atomize in the combustion chamber in an internal combustion engine. The third downside to butanol is that it is more expensive to produce than ethanol, although the higher production cost is partially offset by its higher energy density.

Another potential source of renewable transportation fuel is biomethane refined from biogas. Biogas is a term meaning a combustible mixture of methane and other light gases derived from biogenic sources. It can be combusted directly in some applications, but for use in highway vehicles it is typically purified to closely resemble fossil natural gas for which the vehicles are typically designed. The definition of biogas as given in EISA is sufficiently broad to cover combustible gases produced by biological decomposition of organic matter, as in a landfill or wastewater treatment facility, as well as those produced via thermochemical decomposition of biomass.

Currently, the largest source of biogas is landfill gas collection, where the majority of fuel is combusted to generate electricity, with a small portion being upgraded to methane suitable for use in heavy duty vehicle fleets. Current literature suggests approximately 16 billion gasoline gallons equivalent of biogas (referring to energy content) could potentially be produced in the long term, with about two thirds coming from biomass gasification and about one third coming from waste streams such as landfills and human and animal sewage digestion.[59 60]

Because the majority of the biogas volume estimates assume biomass as a feedstock, we have chosen not to include this fuel in our analyses since we are projecting most available biomass will be used for cellulosic liquid biofuel production in the long term. The remaining biogas potentially available from waste-related sources would come from a large number of small streams requiring purification and connection to storage and/or distribution facilities, which would involve significant economic hurdles. An additional and important source of uncertainty is whether there would be a sufficient number of vehicles configured to consume these volumes of biogas. Thus, we expect future biogas fuel streams to continue to find non-transportation uses such as electrical power generation or facility heating.

d. Other Renewable Fuel

The remaining portion of total renewable fuel not met with advanced biofuel is assumed to come from corn-based ethanol. EISA effectively sets a limit for participation in the RFS program of 15 Bgal of corn ethanol by 2022. It should be noted, however, that there is no specific ''corn-ethanol'' mandated volume, and that any advanced biofuel produced above and beyond what is required for the advanced biofuel requirements could reduce the amount of corn ethanol needed to meet the total renewable fuel standard. This occurs in our projections during the earlier years (2009–2014) in which we project that some fuels could compete favorably with corn ethanol (e.g. biodiesel and imported ethanol). Beginning around 2015, fuels qualifying as advanced biofuels likely will be devoted to meeting the increasingly stringent volume mandates for advanced biofuel. It is also worth noting that more than 15 Bgal of corn ethanol could be produced and RINs generated for that volume under our proposed RFS2 regulations. However, obligated parties would not be required to purchase more than 15 Bgal worth of corn ethanol RINs.

We are assuming for our analysis that sufficient corn ethanol will be produced to meet the 15 Bgal limit. However, this assumes that in the future corn ethanol production is not limited due to environmental constraints, such as water quantity issues (see Section 6.10 of the DRIA). This also assumes that in

[58] To obtain EPA approval for butanol blends as high as 16% by volume would require that the butanol be blended with an approved corrosion inhibitor.

[59] National Renewable Energy Laboratory estimate based on biomass portion available at $45–$55/dry ton. Using POLYSYS Policy Analysis System, Agricultural Policy Analysis Center, University of Tennessee. *http://www.agpolicy.org/polysys.html.* Accessed May 2008.

[60] Milbrandt, A., ''Geographic Perspective on the Current Biomass Resource Availability in the United States.'' 70 pp., NREL Report No. TP–560–39181, 2005.

the future either corn ethanol plants are constructed or modified to meet the 20% GHG threshold, or that sufficient corn ethanol production exists that is grandfathered and not required to meet the 20% threshold. Our current projection is that up to 15 Bgal could be grandfathered, but actual volumes will be determined at the time of facility registration. Refer to Section 1.5.1.4 of the DRIA for more information. Since our current lifecycle analysis estimates that much of the current corn ethanol would not meet the 20% GHG reduction threshold required of non-grandfathered facilities without facility upgrades, then if actual grandfathered corn volumes are less than 15 Bgal it may be necessary to meet the volume mandate with other renewable fuels or through the use of advanced technologies that could improve the corn ethanol lifecycle GHG estimates.

B. Renewable Fuel Production

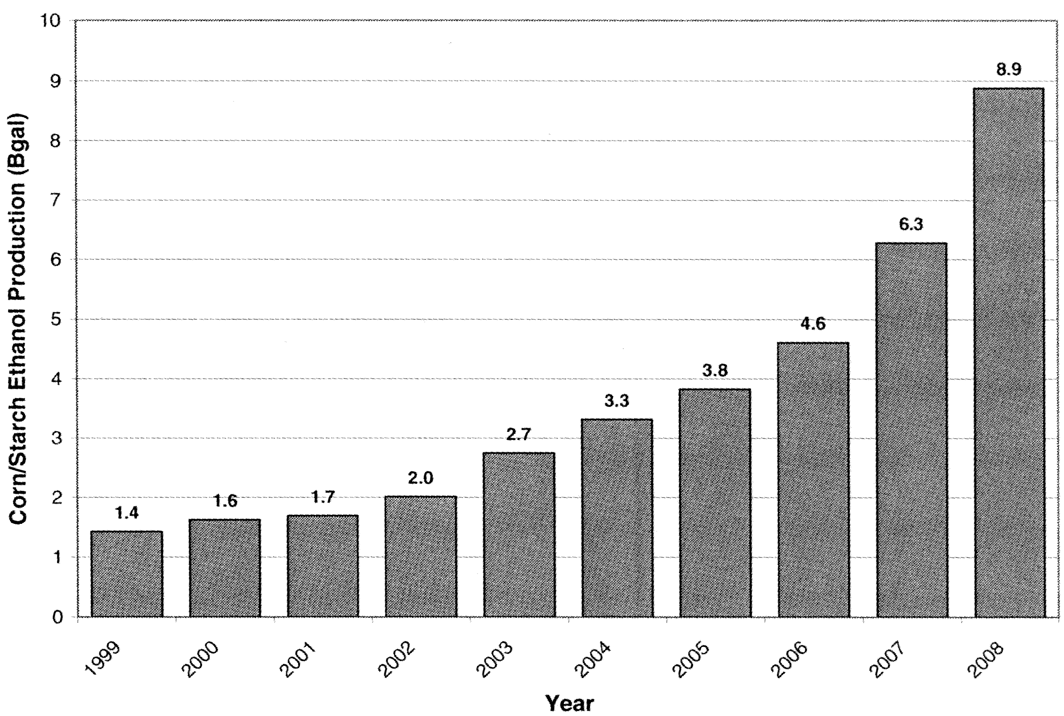
1. Corn/Starch Ethanol

The majority of domestic biofuel production currently comes from plants processing corn and other similarly-processed grains in the Midwest. However, there are a handful of plants located outside the Corn Belt and a few plants processing simple sugars from food or beverage waste. In this section, we will summarize the present state of the corn/starch ethanol industry and discuss how we expect things to change in the future under the proposed RFS2 program.

a. Historic/Current Production

The United States is currently the largest ethanol producer in the world. In 2008, the U.S. produced almost nine billion gallons of fuel ethanol for domestic consumption, the majority of which came from locally-grown corn.[61] Although the U.S. ethanol industry has been in existence since the 1970s, it has rapidly expanded over the past few years due to the phase-out of methyl tertiary butyl ether (MTBE),[62] elevated crude oil prices, state mandates and tax incentives, the introduction of the Federal Volume Ethanol Excise Tax Credit (VEETC),[63] and the implementation of the existing RFS1 program.[64] As shown in Figure V.B.1–1, U.S. ethanol production has grown exponentially over the past decade.

Figure V.B.1-1.
Historical Growth in U.S. Corn/Starch Ethanol Production[65]



[61] Based on total transportation ethanol reported in EIA's March 2009 Monthly Energy Review (Table 10.2) less imports (*http://tonto.eia.doe.gov/dnav/pet/hist/mfeimus1a.htm*).

[62] For more information on how the phase-out of MTBE helped spur ethanol production/consumption, refer to Section V.D.1.

[63] On October 22, 2004, President Bush signed into law H.R. 4520, the American Jobs Creation Act of 2004 (JOBS Bill), which created the Volumetric Ethanol Excise Tax Credit (VEETC). The $0.51/gal VEETC for ethanol blender replaced the former fuel excise tax exemption, blender's credit, and pure ethanol fuel credit. However, the recently-enacted 2008 Farm Bill modifies the alcohol credit so that corn ethanol gets a reduced credit of $0.45/gal and cellulosic biofuel a credit of $1.01/gal effective January 1, 2009.

[64] On May 1, 2007, EPA published a final rule (72 FR 23900) implementing the Renewable Fuel Standard (RFS) required by EPAct. The RFS requires that 4.0 billion gallons of renewable fuel be blended into gasoline/diesel by 2006, growing to 7.5 billion gallons by 2012.

[65] Based on total transportation ethanol reported in EIA's March 2009 Monthly Energy Review (Table 10.2) less imports (*http://tonto.eia.doe.gov/dnav/pet/hist/mfeimus1a.htm*).

As of April 1, 2009, there were 169 corn/starch ethanol plants operating in the U.S. with a combined estimated production capacity of 10.5 billion gallons per year.[66] This does not include a number of ethanol plants that are currently idled.[67] The majority of today's ethanol (over 91% by volume) is produced exclusively from corn. Another 8% comes from a blend of corn and/or similarly processed grains (milo, wheat, or barley) and less than half a percent is produced from cheese whey, waste beverages, and sugars/starches combined. A summary of U.S. ethanol production by feedstock is presented in Table V.B.1–1.

TABLE V.B.1–1—CURRENT CORN/STARCH ETHANOL PRODUCTION CAPACITY BY FEEDSTOCK

Plant feedstock (Primary listed first)	Capacity MGY	Percent of capacity	Number of plants	Percent of plants
Corn [a]	9,605	91.2	144	85.2
Corn, Milo [b]	717	6.8	14	8.3
Corn, Wheat	130	1.2	1	0.6
Milo	3	0.0	1	0.6
Wheat, Milo	50	0.5	1	0.6
Cheese Whey	5	0.0	1	0.6
Waste Beverages [c]	19	0.2	5	3.0
Waste Sugars & Starches [d]	7	0.1	2	1.2
Total	10,535	100	169	100

[a] Includes one facility processing seed corn, two facilities also operating pilot-level cellulosic ethanol plants at these locations, and four facilities planning on incorporating cellulosic feedstocks in the future.
[b] Includes one facility processing a small amount of molasses in addition to corn and milo.
[c] Includes two facilities processing brewery waste.
[d] Includes one facility processing potato waste that intends to add corn in the future.

As shown in Table V.B.1–1, of the 169 operating plants, 161 process corn and/or other similarly processed grains. Of these facilities, 150 utilize dry-milling technologies and the remaining 11 plants rely on wet-milling processes. Dry mill ethanol plants grind the entire kernel and generally produce only one primary co-product: Distillers grains with solubles (DGS). The co-product is sold wet (WDGS) or dried (DDGS) to the agricultural market as animal feed. However, there are a growing number of dry mill ethanol plants pursuing front-end fractionation or back-end extraction to produce fuel-grade corn oil for the biodiesel industry. There are also additional plants pursuing cold starch fermentation and other energy-saving processing technologies. For more on the dry-milling and wet-milling processes as well as emerging advanced technologies, refer to Section 1.4 of the DRIA.

In contrast to dry mill plants, wet mill facilities separate the kernel prior to processing into its component parts (germ, fiber, protein, and starch) and in turn produce other co-products (usually gluten feed, gluten meal, and food-grade corn oil) in addition to DGS. Wet mill plants are generally more costly to build but are larger in size on average.[68] As such, 11.5% of the current grain ethanol production comes from the 11 previously-mentioned wet mill facilities. The remaining eight plants which process cheese whey, waste beverages or sugars/starches, operate differently than their grain-based counterparts. These small production facilities do not require milling and operate a simpler enzymatic fermentation process.

Ethanol production is a relatively resource-intensive process that requires the use of water, electricity, and steam.[69] Steam needed to heat the process is generally produced on-site or by other dedicated boilers.[70] The ethanol industry relies primarily on natural gas. Of today's 169 ethanol production facilities, 142 burn natural gas [71] (exclusively), three burn a combination of natural gas and biomass, one recently started burning a combination of natural gas, landfill biogas and wood, and two burn a combination of natural gas and syrup from the process. In addition, 20 plants burn coal as their primary fuel and one burns a combination of coal and biomass. Our research suggests that 25 plants currently utilize cogeneration or combined heat and power (CHP) technology, although others may exist. CHP is a mechanism for improving overall plant efficiency. Whether owned by the ethanol facility, their local utility, or a third party, CHP facilities produce their own electricity and use the waste heat from power production for process steam, reducing the energy intensity of ethanol production.[72] A summary of the energy sources and CHP technology utilized by today's ethanol plants is found in Table V.B.1–2.

[66] Our April 2009 corn/starch ethanol industry characterization was based on a variety of sources including: Renewable Fuels Association (RFA) Ethanol Biorefinery Locations (updated March 31, 2009); Ethanol Producer Magazine (EPM) Producing plant list (last modified on April 7, 2009), and ethanol producer Web sites. The baseline does not include ethanol plants whose primary business is industrial or food-grade ethanol production nor does it include plants that might be located in the Virgin Islands or U.S. territories. Where applicable, current/historic production levels have been used in lieu of nameplate capacities to estimate production capacity. The April 2009 information presented in this section reflects our most recent knowledge of the corn/starch ethanol industry. However, for various NPRM impact analyses, an earlier May 2008 industry assessment was used. For more on this assessment, refer to Section 1.5.1.5 of the DRIA.

[67] In addition to idled plants, the assessment does not include idled production capacity at facilities that are currently operating at 50% or less than their nameplate capacity.

[68] According to our April 2009 corn ethanol plant assessment, the average wet mill plant capacity was 111 million gallons per year—almost twice that of the average dry mill plant capacity (62 million gallons per year). For more on average plant sizes, refer to Section 1.5.1.1 of the DRIA.

[69] For more information on plant energy requirements, refer to Section 1.5.1.3 of the DRIA.

[70] We are also aware of a couple plants that pull steam directly from a nearby utility.

[71] Facilities were assumed to burn natural gas if the plant boiler fuel was unspecified or unavailable on the public domain.

[72] For more on CHP technology, refer to Section 1.4.1.3 of the DRIA.

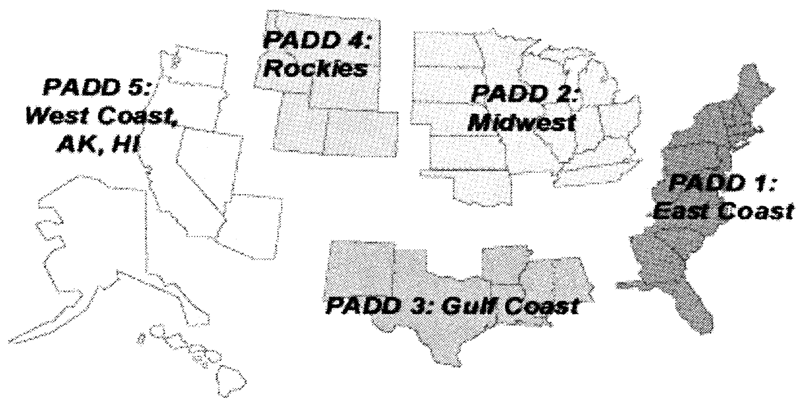
TABLE V.B.1–2—CURRENT CORN/STARCH ETHANOL PRODUCTION CAPACITY BY ENERGY SOURCE

Plant energy source (primary listed first)	Capacity MGY	Percent of capacity	Number of plants	Percent of plants	CHP tech.
Coal [a]	1,868	17.7	20	11.8	9
Coal, Biomass	50	0.5	1	0.6	0
Natural Gas [b]	8,294	78.7	142	84.0	15
Natural Gas, Biomass [c]	113	1.1	3	1.8	1
Natural Gas, Landfill Biogas, Wood	110	1.0	1	0.6	0
Natural Gas, Syrup	101	1.0	2	1.2	0
Total	10,535	100.0	169	100.0	25

[a] Includes four plants that are permitted to burn biomass, tires, petroleum coke, and wood waste in addition to coal and one facility that intends to transition to biomas in the future.
[b] Includes one facility that intends to switch to biomass, one facility that intends to burn thin stillage biogas, and two facilities that might switch to coal in the future.
[c] Includes one facility processing bran in addition to natural gas.

Since the majority of ethanol is made from corn, it is no surprise that most of the plants are located in the Midwest near the Corn Belt. Of today's 169 ethanol production facilities, 151 are located in the 15 states comprising PADD 2. For a map of the Petroleum Administration for Defense Districts or PADDs, refer to Figure V.B.1–2.

Figure V.B.1-2
Petroleum Administration for Defense Districts



As a region, PADD 2 accounts for 94% (or almost 10 billion gallons) of today's estimated ethanol production capacity, as shown in Table V.B.1–3. For more information on today's ethanol plants and a detailed map of their locations, refer to Section 1.5 of the DRIA.

TABLE V.B.1–3—CURRENT CORN/STARCH ETHANOL PRODUCTION CAPACITY BY PADD

PADD	Capacity MGY	Percent of capacity	Number of plants	Percent of plants
PADD 1	150	1.4	3	1.8
PADD 2	9,900	94.0	151	89.3
PADD 3	194	1.8	3	1.8
PADD 4	160	1.5	7	4.1
PADD 5	131	1.2	5	3.0
Total	10,535	100.0	169	100.0

The U.S. ethanol industry is currently comprised of a mixture of company-owned plants and locally-owned farmer cooperatives (co-ops). The majority of today's ethanol production facilities are company-owned, and on average these plants are larger in size than farmer-owned co-ops. Accordingly, company-owned plants account for more than 79% of today's ethanol production capacity.[73] Furthermore, 30% of the total domestic product comes from 38 plants owned by just three different companies—POET Biorefining, Archer Daniels Midland (ADM), and Valero Renewables.[74]

[73] Farmer-owned plant status derived from Renewable Fuels Association (RFA), Ethanol Biorefinery Locations (updated March 31, 2009). For more on average plant sizes, refer to Section 1.5.1 of the DRIA.

[74] Valero recently entered into the renewable fuels business by acquiring five idled corn ethanol plants and one construction site formerly owned by VeraSun Energy Corporation. Valero has since

Continued

b. Forecasted Production Under RFS2

As highlighted above, 10.5 billion gallons of corn/starch ethanol plant capacity was online as of April 1, 2009. So even if no additional capacity was added, U.S. ethanol production would grow from 2008 to 2009, provided facilities continue to operate at or above today's production levels. And despite today's temporary unfavorable market conditions (i.e., low ethanol market values), we expect the ethanol industry will continue to expand in the future under RFS2. Although there is not a set corn ethanol standard, EISA allows for 15 billion gallons of the 36-billion gallon renewable fuel standard to be met by conventional biofuels. And we expect that corn and other sugar or starch-based ethanol will fulfill this requirement. Furthermore, we project that all new corn/starch ethanol plant capacity brought online under RFS2 would either meet the conventional biofuel GHG threshold requirement [75] or meet the grandfathering requirement (for more information, refer to Section 1.5.1.4 of the DRIA).

In addition to the 169 corn/starch ethanol plants that are currently online today, 36 plants are presently idled. Some of these constructed facilities (namely smaller ethanol plants) have been idled for quite some time, whereas other plants have just recently been put into ''hot idle'' mode. A number of ethanol producers (e.g., VeraSun) are idling operations, putting projects on hold, selling off plants, and even filing for Chapter 11 bankruptcy. In addition, we are aware of two facilities that are currently operating at 50% or less than their nameplate capacity. As crude oil and gasoline prices rise again in the future, corn ethanol production will become more viable again and we expect that these plants will resume operations. At the time of our April 2009 ethanol industry assessment, there were also 19 new ethanol plants under construction in the U.S, and two plant expansion projects underway. While many of these projects are also on hold due to the current economic conditions, we expect these facilities will eventually come online under the RFS2 program. A summary of the projected industry growth is found in Table V.B.1–4.[76]

TABLE V.B.1–4—POTENTIAL INDUSTRY EXPANSION UNDER RFS2

	Growth in ethanol production				
	Plants currently online	Idled plants/ capacity [a]	New construction projects	Expansion projects	Total
Plant Capacity (MGY)	10,535	2,471	1,955	80	15,042
Total No. of Plants	169	36	19	2	226

[a] Includes the idled plant capacity of the two facilities that are currently operating at 50% or less than nameplate capacity.

While theoretically it only takes 12 to 18 months to build an ethanol plant,[77] the rate at which new plant capacity comes online will be dictated by market conditions, which will in part be influenced by the RFS2 requirements. As mentioned above, today's proposed program will create a growing demand for corn ethanol reaching 15 billion gallons by 2015. However, it is possible that market conditions could drive demand even higher. Whether the nation will overcomply with the corn ethanol standard is uncertain and will be determined by feedstock availability/ pricing, crude oil pricing, and the relative ethanol/gasoline price relationship. To measure the impacts of the proposed RFS2 program, we assumed that corn ethanol production would not exceed 15 billion gallons. We also assumed that all growth would come from new plants or plant expansion projects (in addition to idled plants being brought back online).[78] However, it is possible that some of the growth could come from minor process improvements (e.g., debottlenecking) at existing facilities.

Once all the aforementioned projects are complete, we project that there would be 226 corn/starch ethanol plants operating in the U.S. with a combined production capacity of around 15 billion gallons per year. Much like today's ethanol industry, the overwhelming majority of new production capacity (93% by volume) is expected to come from corn-fed plants. Another 7% is forecasted to come from plants processing a blend of corn and other grains, and a very small increase is projected to come from idled cheese whey and waste beverage plants coming back online. A summary of the forecasted ethanol production by feedstock under the RFS2 program is found in Table V.B.1–5.

TABLE V.B.1–5—PROJECTED RFS2 CORN/STARCH ETHANOL PRODUCTION CAPACITY BY FEEDSTOCK

Plant feedstock (primary listed first)	Additional production		Total RFS2 estimate	
	Capacity MGY	Number of plants	Capacity MGY	Number of plants
Corn [a]	4,197	49	13,802	193
Corn, Milo [b]	185	3	902	17
Corn, Wheat	8	1	138	2
Corn, Wheat, Milo	110	2	110	2
Milo	0	0	3	1
Wheat, Milo	0	0	50	1

purchased two more idled VeraSun plants, but they have not been brought back online yet.

[75] The lifecycle assessment values which assume a 2% discount rate over a 100-year timeframe.

[76] Idled plants and construction projects based on Renewable Fuels Association (RFA) Ethanol Biorefinery Locations (updated March 31, 2009); Ethanol Producer Magazine (EPM) Not Producing and Under Construction plant lists (last modified on April 7, 2009), ethanol producer Web sites, and follow-up correspondence with ethanol producers. It is worth noting that for our industry assessment, ''under construction'' implies that more than just a ground breaking ceremony has taken place.

[77] For more information on plant build rates, refer to Section 1.2.5 of the RIA.

[78] For our NPRM impact analyses, we relied on an earlier May 2008 industry assessment. For more information, refer to Section 1.5.1.5 of the DRIA.

TABLE V.B.1–5—PROJECTED RFS2 CORN/STARCH ETHANOL PRODUCTION CAPACITY BY FEEDSTOCK—Continued

Plant feedstock (primary listed first)	Additional production		Total RFS2 estimate	
	Capacity MGY	Number of plants	Capacity MGY	Number of plants
Cheese Whey	3	1	8	2
Waste Beverages [c]	4	1	23	6
Waste Sugars & Starches [d]	0	0	7	2
Total	4,507	57	15,042	226

[a] Includes one facility processing seed corn, another facility processing small amounts of whey, two facilities also operating pilot-level cellulosic ethanol plants at these locations, and four facilities planning on incorporating cellulosic feedstocks in the future.
[b] Includes one facility processing a small amount of molasses in addition to corn and milo.
[c] Includes two facilities processing brewery waste.
[d] Includes one facility processing potato waste that intends to add corn in the future.

Based on current industry plans, the majority of additional corn/grain ethanol production capacity (almost 84% by volume) is predicted to come from new or expanded plants burning natural gas.[79] Additionally, we are forecasting one new plant and a reopening of another plant relying on manure biogas. We are also predicting expansions at three coal-fired ethanol plants.[80] Of the 55 new ethanol plants, our research indicates that five would utilize cogeneration, bringing the total number of CHP facilities to 30. A summary of the projected near-term ethanol plant energy sources is found in Table V.B.1–6.

TABLE V.B.1–6—PROJECTED NEAR-TERM CORN/STARCH ETHANOL PRODUCTION CAPACITY BY ENERGY SOURCE

Plant energy source (primary listed first)	Additional production		Total RFS2 estimate		
	Capacity MGY	Number of plants	Capacity MGY	Number of plants	CHP tech.
Coal [a]	610	2	2,478	22	11
Coal, Biomass	0	0	50	1	0
Manure Biogas	134	2	134	2	0
Natural Gas [b]	3,763	53	12,056	195	18
Natural Gas, Biomass [c]	0	0	113	3	1
Natural Gas, Landfill Biogas, Wood	0	0	110	1	0
Natural Gas, Syrup	0	0	101	2	0
Total	4,507	57	15,042	226	30

[a] Includes six plants that are permitted to burn biomass, tires, petroleum coke, and wood waste in addition to coal and one facility that intends to transition to biomass in the future.
[b] Includes one facility that intends to switch to biomass, one facility that intends to burn thin stillage biogas, and six facilities that might switch to coal in the future.
[c] Includes one facility processing bran in addition to natural gas.

The information in Table V.B.1.6 is based on short-term industry production plans at the time of our April 1, 2009 plant assessment. However, we are anticipating growth in advanced ethanol production technologies under the proposed RFS2 program. We project that fuel prices will drive a large number of corn ethanol plants to transition from conventional boiler fuels to advanced biomass-based feedstocks. We also believe that fossil fuel/electricity prices will drive a number of ethanol producers to pursue CHP technology. For more on our projected 2022 utilization of these technologies under the RFS2 program, refer to Section 1.5.1.3 of the DRIA.

Under the proposed RFS2 program, the majority of new ethanol production is expected to originate from PADD 2, close to where most of the corn is grown. However, there are a number of ''destination'' ethanol plants being built outside the Midwest in response to production subsidies, E10/E85 retail pump incentives, and state mandates. A summary of the forecasted ethanol production by PADD under the RFS2 program can be found in Table V.B.1–7.

[79] Facilities were assumed to burn natural gas if the plant boiler fuel was unspecified or unavailable on the public domain.

[80] Two of the three coal-fired plant expansions appear as new plants in Table V.B.1–6. This is because two of the expansion projects consist of adding dry milling plant capacity to an existing wet mill plant. However, our interpretation is that these facilities will rely on the same (potentially expanded) coal-fired boilers for process steam. Since all the aforementioned coal-fired ethanol production facilities appear to have commenced construction prior to December 19, 2007, we project that the ethanol produced at these facilities will be grandfathered under the proposed RFS2 rule. For more on our grandfathered volume estimate, refer to Section 1.5.1.4 of the DRIA.

TABLE V.B.1–7—PROJECTED RFS2 CORN/STARCH ETHANOL PRODUCTION CAPACITY BY PADD

PADD	Additional production		Total RFS2 Estimate	
	Capacity MGY	Number of plants	Capacity MGY	Number of plants
PADD 1	178	3	328	6
PADD 2	3,566	43	13,466	194
PADD 3	350	4	544	7
PADD 4	50	1	210	8
PADD 5	363	6	494	11
Total	4,507	57	15,042	226

2. Cellulosic Biofuel

Ethanol currently dominates U.S. biofuel production, and more specifically, ethanol produced from corn and other grains. However, cellulosic feedstocks have the potential to greatly expand domestic ethanol production, both volumetrically and geographically. It is also possible to produce synthetic diesel fuel from cellulosic feedstocks (also known as ‘‘cellulosic diesel’’) through a Fischer-Tropsch gasification process or a thermal depolymerization process. We are also aware of one company using live bacteria to break down biomass and produce cellulosic diesel and other petroleum replacements. Before wide-scale commercialization of cellulosic biofuel can occur in today's marketplace, technical and logistical barriers must be overcome. In addition to today's RFS2 program which sets aggressive goals for all ethanol production, the Department of Energy (DOE) and other federal and state agencies are helping to spur industry growth.

a. Current Production/Plans

The cellulosic biofuel industry is essentially in its infancy. With the exception of a 20 million-gallon-per year cellulosic diesel plant recently opened by Cello Energy in Bay Minette, AL, the majority of facilities in operation today are small pilot- or demonstration-level plants. Most of these facilities operate intermittently and produce insignificant volumes of biofuel. Some researchers are focusing on processing corn residues, e.g., corn stover, cobs, and/or fiber. Some are focusing on other agricultural residues such as sugarcane bagasse, rice and wheat straw. Others are looking at waste products such as forestry residues, citrus residues, pulp or paper mill waste, municipal solid waste (MSW), and construction and demolition (C&D) debris. Dedicated energy crops including switchgrass and poplar trees are also being investigated.

Based on an April 2009 assessment of information available on the public domain, there are currently 25 pilot- and demonstration-level (or smaller) cellulosic ethanol plants operating in the United States. However, only 9 of these plants report measurable volumes of ethanol production. In addition, we are aware of one pilot-level cellulosic diesel plant in addition to the commercial-level Cello Energy plant.[81] A summary of these 11 facilities totaling just over 23 million gallons of annual production capacity is provided in Table V.B.2–1. The date listed in the table indicates when the facility first began operations. For more on the existing cellulosic ethanol and diesel plants, refer to Sections 1.5.3.1 and 1.5.3.3 of the DRIA.

TABLE V.B.2–1—EXISTING CELLULOSIC BIOFUEL PLANTS

Company or organization name	Location	Feedstocks	Prod cap (MGY)	Est. Op. date	Conv. tech. [a]
Cellulosic Ethanol					
Abengoa Bioenergy Corporation [b]	York, NE	Wheat straw, corn stover, energy crops	0.02	Sep-07	Bio.
Bioengineering Resources, Inc. (BRI)	Fayetteville, AR	MSW, wood waste, coal	0.04	1998	Therm.
BPI & Universal Entech	Phoenix, AZ	Paper waste (sorted MSW)	0.01	2004	Bio.
Gulf Coast Energy	Livingston, AL	Wood waste (sorted MSW)	0.20	Dec-08	Therm.
Mascoma Corporation	Rome, NY	Wood chips	0.20	Feb-09	Bio.
POET Project Bell [b]	Scotland, SD	Corn cobs & fiber	0.02	Jan-09	Bio.
Verenium	Jennings, LA	Sugarcane bagasse	0.05	2006	Bio.
Verenium	Jennings, LA	Sugarcane bagasse, wood, energy cane	1.50	Feb-09	Bio.
Western Biomass Energy LLC. (WBE)	Upton, WY	Wood waste (softwood)	1.50	2007	Bio.
Cellulosic Diesel					
Cello Energy	Bay Minette, AL	Wood chips, hay	20.00	Dec-08	CatDep.
Bell BioEnergy	Fort Stewart, GA	Wood chips	0.01	Dec-08	Bact.
Total Existing Production Capacity >23 MGY					

[a] Bio = biochemical pre-treatment, Therm = thermochemical conversion, CatDep = catalytic depolymerization, Bact = involves the use of live bacteria to break down biomass for cellulosic diesel production.
[b] Cellulosic pilot plant is collocated with a corn ethanol plant.

[81] Our April 2009 cellulosic ethanol industry characterization was based on researching DOE- and USDA-supported projects, plants referenced in HART's Ethanol & Biodiesel News (through the April 14, 2009 issue), plants included on the Cellulosic Ethanol Site (*http://www.thecesite.com/*), and plants referenced on other biofuel industry Web sites.

To date, the majority of cellulosic ethanol research has focused on biochemical pre-treatment technologies, i.e., the use of acids and/or enzymes to break down cellulosic materials into fermentable sugars. However, there are a growing number of companies investigating the thermochemical pathway which involves gasification of biomass into a synthesis gas or pyrolysis of biomass into a bio-crude oil for processing. Cellulosic diesel can also be made from thermochemical as well as other processes. Many companies are also researching the potential of co-firing biomass to produce plant energy in addition to biofuels. For more on cellulosic biofuel processing technologies, refer to Section 1.4.3 of the DRIA.

In addition to the existing facilities in Table V.B.2–1, our April 2009 industry assessment suggests that there are currently three cellulosic ethanol plants under construction in the United States. Like the existing plants, two are pilot-level facilities that are still working towards proving their conversion technologies. However, Range Fuels, a company that received $76 million from DOE and an $80 loan guarantee from USDA to build one of the first commercial-scale cellulosic ethanol plants in the U.S., is currently building a 40 million gallon per year plant in Soperton, GA.[82] At this time, the company is just working on the initial 10 million gallon per year phase. Bell Bioenergy, a company that received $7.5 million in funding from the Department of Defense to convert biomass into cellulosic diesel using live bacteria, also has six pilot plants under construction in various locations through the country. A summary of these nine cellulosic biofuel plants, totaling over 10 million gallons of annual production capacity, is presented in Table V.B.2–2.

As shown in Tables V.B.2–1 and V.B.2–2, unlike corn ethanol production, which is primarily located in the Midwest near the Corn Belt, cellulosic biofuel production is spread throughout the country. The geographic distribution of plants is due to the wide variety and availability of cellulosic feedstocks. Corn stover is found primarily in the Midwest, while the Pacific Northwest, the Northeast, and the Southeast all have forestry residues. Some southern states have access to sugarcane bagasse and citrus waste while MSW and C&D debris are available in highly populated areas throughout the country. For more information on cellulosic feedstock availability, refer to Section 1.1.2 of the DRIA.

TABLE V.B.2–2—CELLULOSIC BIOFUEL PLANTS CURRENTLY UNDER CONSTRUCTION

Company plant name	Location	Feedstocks	Prod cap (MGY)	Est. op. date.	Conv. tech.[a]
Cellulosic Ethanol					
Coskata	Madison, PA	MSW, natural gas, woodchips, bagasse, switchgrass.	0.04	Jul–09	Therm.
DuPont Dansico Cellulosic Ethanol (DDCE)	Vonore, TN	Corn cobs then switchgrass	0.25	Dec–09	Bio.
Range Fuels[b]	Soperton, GA	Wood waste, switchgrass	10.00	Dec–09	Therm.
Cellulosic Diesel					
Bell Bio-Energy	Fort Lewis, WA	Cellulose	0.01	2009	Bact.
Bell Bio-Energy	Fort Drum, NY	Cellulose	0.01	2009	Bact.
Bell Bio-Energy	Fort AP Hill, VA	Cellulose	0.01	2009	Bact.
Bell Bio-Energy	Fort Bragg, NC	Cellulose	0.01	2009	Bact.
Bell Bio-Energy	Fort Benning, GA	Cellulose	0.01	2009	Bact.
Bell Bio-Energy	San Pedro, CA	Cellulose	0.01	2009	Bact.
Total Under Construction Production Capacity >10 MGY					

[a] Bio = biochemical pre-treatment, Therm = thermochemical conversion, Bact = involves the use of live bacteria to break down biomass for cellulosic diesel production.

[b] The first 10 MGY phase is currently under construction in Soperton, GA. Once this second 30 MGY phase is added, the plant will be capable of producing 40 MGY of cellulosic ethanol.

Increased public interest, government support, technological advancement, and the recently-enacted EISA have helped spur many plans for new cellulosic biofuel plants. Although more and more plants are being announced, most are limited in size and contingent upon technology breakthroughs and efficiency improvements at the pilot or demonstration level. Additionally, because cellulosic biofuel production has not yet been proven on the commercial level, financing of these projects has primarily been through venture capital and similar funding mechanisms, as opposed to conventional bank loans.

Consequently, recently-announced Federal grant and loan guarantee programs may serve as a significant asset to the cellulosic biofuel industry in this area. In February 2007, DOE announced that it would invest up to $385 million in six commercial-scale ethanol projects over the next four years. Since the announcement, two of the companies have forfeited their funding. Iogen has decided to locate its first commercial-scale plant in Canada and Alico has discontinued plans to produce ethanol all together. The four remaining ‘‘pioneer’’ plants (including Range Fuels) hold promise and could very well be some of the first plants to demonstrate the commercial-scale viability of cellulosic ethanol production. However, there is still more to be learned at the pilot level. Although technologies needed to convert

[82] Range Fuels' ultimate goal is to expand the Soperton, GA facility to produce 100 million gallons of cellulosic ethanol per year.

cellulosic feedstocks into ethanol (and diesel) are becoming more and more understood, there are still a number of efficiency improvements that need to occur before cellulosic biofuels can compete in today's marketplace.

In May 2007, DOE announced that it would provide up to $200 million to help fund small-scale cellulosic biorefineries experimenting with novel processing technologies that could later be expanded to commercial production facilities. Four recipients were announced in January 2008 and three more were announced in April 2008. Three months later, DOE announced that it would provide $40 million more to help fund two additional small-scale plants. Of the nine announced small-scale plants, seven were pursuing cellulosic ethanol production (including Verenium Corp.) and two are pursuing cellulosic diesel production. However, Lignol Innovations, recently suspended plans to build a 2.5 million gallon per year cellulosic ethanol plant in Grand Junction, CO due to market uncertainty.

The Department of Energy has also introduced a loan guarantee program to help reduce risk and spur investment in projects that employ new, clean energy technologies. In October 2007, DOE issued final regulations and invited 16 project sponsors who submitted pre-applications to submit full applications for loan guarantees. Of those who were invited to participate, five were pursuing cellulosic biofuel production. However, only three companies appear to still be eligible.[83] Of the three remaining companies, two are pursuing cellulosic ethanol production (and are also DOE grant recipients) and one is pursuing cellulosic diesel production. The U.S. Department of Agriculture is also providing an $80 million loan guarantee to Range Fuels to help support construction of its 40 million-gallon-per-year cellulosic ethanol plant in Soperton, GA. For more on information on Federal support for biofuel production, refer to Section 1.5.3 of the DRIA.

In addition to the companies receiving government funding, there are a growing number of privately-funded companies (including Cello Energy) with plans to build more cellulosic biofuel plants in the United States. These facilities range in size from pilot- and demonstration-level plants (similar to those currently operational or under construction), to small commercial plants (similar to the four commercial-scale plants receiving DOE funding), to large commercial plants (similar in size to an average corn ethanol plant). These projects are also at various stages of planning. According to our April 2009 industry assessment, 11 plants are currently at advanced stages of planning and likely to go online in the near future. Along with those plants currently operational or under construction, we believe that these facilities will enable the U.S. to meet the 100 million gallon cellulosic biofuel standard in 2010. For a summary of the plants and their respective projected contributions, refer to Table V.B.2–3 below. For a greater discussion on these and other cellulosic biofuel projects, refer to Section 1.5.3.1 of the DRIA.

TABLE V.B.2–3—PROJECTED CELLULOSIC BIOFUEL PRODUCTION IN 2010

Company or organization name	Location	Prod cap (MGY)	Est. op. date	Est. 2010 million gallons	Est 2010 ETOH-equiv. million gallons
Cellulosic Ethanol					
BPI & Universal Entech	Phoenix, AZ	0.01	Online	0.01	0.01
POET Project Bell	Scotland, SD	0.02	Online	0.02	0.02
Abengoa Bioenergy Corporation	York, NE	0.02	Online	0.02	0.02
Bioengineering Resources, Inc. (BRI)	Fayetteville, AK	0.04	Online	0.04	0.04
Verenium	Jennings, LA	0.05	Online	0.05	0.05
Gulf Coast Energy	Livingston, AL	0.20	Online	0.20	0.20
Mascoma Corporation	Rome, NY	0.20	Online	0.20	0.20
Verenium	Jennings, LA	1.50	Online	1.50	1.50
Western Biomass Energy, LLC. (WBE)	Upton, WY	1.50	Online	1.50	1.50
Coskata	Madison, PA	0.04	Jul-09	0.04	0.04
DuPont Dansico Cellulosic Ethanol (DDCE).	Vonore, TN	0.25	Dec-09	0.25	0.25
Range Fuels	Soperton, GA	10.0	Dec-09	10.0	10.0
Ecofin/Alltech	Springfield, KY	1.30	2010	0.65	0.65
Fulcrum Bioenergy	Storey County, NV	10.50	2010	5.25	5.25
ICM Inc.	St. Joseph, MO	1.50	2010	0.75	0.75
RSE Pulp & Chemical	Old Town, ME	2.20	2010	1.10	1.10
ZeaChem	Boardman, OR	1.50	2010	0.75	0.75
ClearFuels Technology	Kauai, HI	1.50	End of 2010	0.38	0.38
Southeast Renewable Fuels LLC	Clewiston, FL	20.00	End of 2010	5.00	5.00
Cellulosic Diesel					
Cello Energy	Bay Minette, AL	20.00	Online	20.00	32.00
Bell Bio-Energy	Fort Stewart, GA	0.01	2008	0.01	0.01
Bell Bio-Energy	Fort Lewis, WA	0.01	2009	0.01	0.01
Bell Bio-Energy	Fort Drum, NY	0.01	2009	0.01	0.01
Bell Bio-Energy	Fort AP Hill, VA	0.01	2009	0.01	0.01
Bell Bio-Energy	Fort Bragg, NC	0.01	2009	0.01	0.01
Bell Bio-Energy	Fort Benning, GA	0.01	2009	0.01	0.01
Bell Bio-Energy	San Pedro, CA	0.01	2009	0.01	0.01

[83] Iogen and Alico have also forfeited a potential loan guarantee from DOE.

TABLE V.B.2–3—PROJECTED CELLULOSIC BIOFUEL PRODUCTION IN 2010—Continued

Company or organization name	Location	Prod cap (MGY)	Est. op. date	Est. 2010 million gallons	Est 2010 ETOH-equiv. million gallons
Cello Energy	TBD (AL)	50.00	2010	16.67	26.67
Cello Energy	TBD (AL)	50.00	2010	16.67	26.67
Cello Energy	TBD (GA)	50.00	2010	16.67	26.67
Flambeau River Biofuels	Park Falls, WI	6.00	2010	3.00	4.80
Total 2010 Production Forecast				100.74	144.57

b. Federal/State Production Incentives

In addition to helping fund a series of small-scale cellulosic biofuel plants, the Department of Energy, along with the U.S. Department of Agriculture (USDA), is also helping to fund critical research to help make cellulosic biofuel production more commercially viable. In March 2007, DOE awarded $23 million in grants to four companies and one university to develop more efficient microbes for ethanol refining. In June 2007, DOE and USDA awarded $8.3 million to 10 universities, laboratories, and research centers to conduct genomics research on woody plant tissue for bioenergy. Later that same month, DOE announced plans to spend $375 million to build three bioenergy research centers dedicated to accelerating research and development of cellulosic ethanol and other biofuels. The centers, which will each focus on different feedstocks and biological research challenges, will be located in Oak Ridge, TN, Madison, WI, and Berkeley, CA. In December 2007, DOE awarded $7.7 million to one company, one university, and two research centers to demonstrate the thermochemical conversion process of turning grasses, stover, and other cellulosic materials into biofuel. In February 2008, DOE awarded another $33.8 million to three companies and one research center to support the development of commercially-viable enzymes to support cellulose hydrolysis, a critical step in the biochemical breakdown of cellulosic feedstocks. Finally, in March 2008, DOE and USDA awarded $18 million to 18 universities and research institutes to conduct research and development of biomass-based products, biofuels, bioenergy, and related processes. Since 2007, DOE has announced more than $1 billion and since 2006, USDA has invested almost $600 million for the research, development, and demonstration of new biofuel technology.

Numerous states are also offering grants, tax incentives, and loan guarantees to help encourage biofuel production. The majority of efforts are centered on expanding ethanol production, and more recently, cellulosic ethanol production.[84] According to a July 2008 assessment of DOE's Energy Efficiency and Renewable Energy (EERE) Web site,[85] 33 states currently offer some form of ethanol production incentive. The incentives range from support for ethanol producers to support for research and development companies to support for feedstock suppliers. Kansas, Maryland, and South Carolina each offer specific incentives towards cellulosic ethanol production. Kansas offers revenue bonds through the Kansas Development Finance Authority to help fund construction or expansion of a cellulosic ethanol plant. Additionally, these newly-built or expanded facilities are exempt from state property tax for 10 years. Maryland offers a credit towards state income tax for 10% of cellulosic ethanol research and development expenses. They also have a $0.20 per gallon production credit for cellulosic ethanol. South Carolina gives a $0.30 per gallon production credit to cellulosic ethanol producers that meet certain requirements.

In addition to individual state incentives, a group of states in the Midwest have joined together to pursue ethanol and other biofuel production and usage goals as part of the Midwest Energy Security and Climate Stewardship Platform.[86] As of June 2008, Indiana, Iowa, Kansas, Michigan, Minnesota, North Dakota, Ohio, South Dakota, and Wisconsin had all committed to these goals which emphasize energy independence through the growth of cellulosic ethanol production and availability of E85. The Platform goals are to produce cellulosic ethanol on a commercial level by 2012 and to have E85 offered at one-third of refueling stations by 2025. They also want to reduce the energy intensity of ethanol production and supply 50% of their transportation fuel needs by regionally produced biofuels by 2025.

Finally, the passage of the Food, Conservation, and Energy Act of 2008 (also known as the ''2008 Farm Bill'') is also helping to spur cellulosic ethanol production and use.[87] The 2008 Farm Bill modified the existing $0.51 per gallon alcohol blender credit to give preference to ethanol and other biofuels produced from cellulosic feedstocks. Corn ethanol now receives a reduced credit of $0.45/gal while cellulosic biofuel earns a credit of $1.01/gal.[88] The 2008 Farm Bill also has provisions that enable USDA to assist with the commercialization of second-generation biofuels. Section 9003 authorizes loan guarantees for the development, construction and retrofitting of commercial scale biorefineries. Section 9004 provides payments to biorefineries to replace fossil fuels with renewable biomass. Section 9005 provides payments to producers to support and ensure production of advanced biofuels. And finally, Section 9008 provides competitive grants, contracts and financial assistance to enable eligible entities to carry out research, development, and demonstration of biofuels and biomass-based based products. For more information on the Federal and state production incentives outlined in this subsection, refer to Section 1.5.3.2 of the DRIA.

c. Feedstock Availability

A wide variety of feedstocks can be used for cellulosic ethanol production, including: Agricultural residues,

[84] For more on state-level biodiesel production incentives, refer to Section 1.5.4 of the DRIA.

[85] The database of ethanol incentives and laws by state is available at: *http://www.eere.energy.gov/afdc/ethanol/incentives_laws.html*.

[86] Midwest Governors Association, ''Energy Security and Climate Stewardship Platform for the Midwest 2007'' (*http://www.midwesterngovernors.org/resolutions/Platform.pdf*)

[87] The Food, Conservation, and Energy Act of 2008 (*http://www.usda.gov/documents/Bill_6124.pdf*)

[88] Refer to Part II, Subparts A and B (Sections 15321 and 15331).

forestry biomass, municipal solid waste, construction and demolition waste, and energy crops. These feedstocks are much more difficult to convert into ethanol than traditional starch/corn crops or at least require new and different processes because of the more complex structure of cellulosic material.

One potential barrier to commercially viable cellulosic biofuel production is high feedstock cost. As such, fuel producers will seek to acquire inexpensive feedstocks in sufficient quantities to lower their production costs and the risk of feedstock supply shortages. At least initially, the focus will be on feedstocks that are readily available, already produced or collected for other reasons, and even waste biomass which currently incurs a disposal fee. Consequently, initial volumes of cellulosic biofuels may benefit from low-cost feedstocks. However, to reach 16 Bgal will likely require reliance on more expensive feedstock sources purposely grown and or harvested for conversion into cellulosic biofuel.

To determine the likely cellulosic feedstocks for production of 16 billion gallons cellulosic biofuel by 2022, we analyzed the data and results from various sources. Sources include agricultural modeling from the Forestry Agriculture Sector Optimization Model (FASOM) to establish the most economical agriculture residues and energy crops (see Section IX for more details on the FASOM), consultation with USDA–Forestry Sector experts for forestry biomass supply curves, and feedstock assessment estimates for urban waste.[89]

An important assumption in our analysis projecting which feedstocks will be used for producing cellulosic ethanol is that an excess of feedstock would have to be available for producing the biofuel. Banks are anticipated to require excess feedstock supply as a safety factor to ensure that the plant will have adequate feedstock available for the plant, despite any feedstock emergency, such as a fire, drought, infestation of pests etc. For our analysis we assumed that twice the feedstock of MSW, C&D waste, and forest residue would have to be available to justify the building of a cellulosic ethanol plant. For corn stover, we assumed 50% more feedstock than necessary. We used a lower safety factor for corn stover because it could be possible to remove a larger percentage of the corn stover in any given year (usually only 50% or less of corn stover is assumed to be sustainably removed in any one year).[90] As a result, our projected cellulosic facilities only consume a portion of the total supply of feedstock available. After a cellulosic facility is fully established and certain risks are reduced, it is entirely possible that the facility may choose to consume excess feedstock in order to expand production. In addition, more facilities could potentially be built if financial investors required less excess supply. Since we are assessing the impact of producing 16 Bgal of cellulosic biofuel by 2022, this analysis does not project the construction of more facilities or more feedstocks consumed than necessary.

Another assumption that we made is that if multiple feedstocks are available in an area, each would be used as feedstocks for a prospective cellulosic ethanol plant. For example, a particular area might comprise a small or medium sized city, some forest and some agricultural land. We would include the MSW and C&D wastes available from the city along with the corn stover and forest residue for projecting the feedstock that would be processed by the particular cellulosic ethanol plant.

The following subsections describe the availability of various cellulosic feedstocks and the estimated amounts from each feedstock needed to meet the EISA requirement of 16 Bgal of cellulosic biofuel by 2022. Refer to Section V.B.2.c.iv for the summarized results of the types and volumes of cellulosic feedstocks chosen based on our analyses.

i Urban Waste

Cellulosic feedstocks available at the lowest cost to the ethanol producer will likely be chosen first. This suggests that urban waste which is already being gathered today and which incurs a fee for its disposal may be among the first to be used. Urban wood wastes are used in a variety of ways. Most commonly, wastes are ground into mulch, dumped into land-fills, or incinerated with other municipal solid waste (MSW) or construction and demolition (C&D) debris. Urban wood wastes include a variety of wood resources such as wood-based municipal solid waste and wood debris from construction and demolition.

MSW consists of paper, glass, metals, plastics, wood, yard trimmings, food scraps, rubber, leather, textiles, etc. The portion of MSW containing cellulosic material and typically the focus for biofuel production is wood and yard trimmings. In addition, paper, which made up approximately 34% of the total MSW generated in 2006, could potentially be converted to cellulosic biofuel.[91] Food scraps could also be converted to cellulosic biofuel, however, it was noted by an industry group that this feedstock could be more difficult to convert to biofuel due to challenges with separation, storage, transport, and degradation of the materials. Although recycling/recovery rates are increasing over time, there appears to still be a large fraction of biogenic material that ends up unused and in land-fills. C&D debris is typically not available in wood waste assessments, although some have estimated this feedstock based on population. In 1996, this was estimated to be approximately 124 million metric tons of C&D debris.[92] Only a portion of this, however, would be made of woody material. Utilization of such feedstocks could help generate energy or biofuels for transportation. However, despite various assessments on urban waste resources, there is still a general lack of reliable data on delivered prices, issues of quality (potential for contamination), and lack of understanding of potential competition with other alternative uses (e.g. recycling, burning for electricity).

We estimated that 42 million dry tons of MSW (wood and yard trimmings & paper) and C&D wood waste could be available for producing biofuels after factoring in several assumptions (e.g. percent contamination, percent recovered or combusted for other uses, and percent moisture).[93 94] We assumed that approximately 25 million dry tons (of the total 42 million dry tons) would be used. However, many areas of the U.S. (e.g. much of the Rocky Mountain States) have such sparse resources that a MSW and C&D cellulosic facility would not likely be justifiable. We did assume that in areas with other

[89] It is important to note that our plant siting analysis for cellulosic ethanol facilities used the most current version of outputs from FASOM at the time, which was from April 2008. Since then, FASOM has been updated to reflect better assumptions. Therefore, the version used for the NPRM in Section IX on economic impacts is slightly different than the one we used here. We do not believe that the differences between the two versions are enough to have a major impact on the plant siting analysis.

[90] The FASOM results do not take into consideration these feedstock safety margins. Safety margins were used, however, for the plant siting analysis described in Section V.B.2.c.v.

[91] EPA. Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures for 2006.

[92] Fehrs, J., ''Secondary Mill Residues and Urban Wood Waste Quantities in the United States—Final Report,'' Northeast Regional Biomass Program Washington, DC, December 1999.

[93] Wiltsee, G., ''Urban Wood Waste Resource Assessment,'' NREL/SR–570–25918, National Renewable Energy Laboratory, November 1998.

[94] Biocycle, ''The State of Garbage in America,'' Vol. 47, No. 4, 2006, p. 26.

cellulosic feedstocks (forest and agricultural residue), that the MSW would be used even if the MSW could not justify the installation of a plant on its own. Therefore, we have estimated that urban waste could help contribute to the production of approximately 2.2 billion gallons of ethanol.[95] A more detailed discussion on this analysis is included in the DRIA Chapter 1. Subsequent to initiating our analysis, however, we realized that the revised renewable biomass definition in the statute may preclude the use of most MSW. See Section III.B.4 for a discussion of renewable biomass. When the definition of renewable biomass is finalized, it could preclude the use of some of the lowest cost potential feedstocks, including waste paper and C&D waste, for use in producing cellulosic biofuel for use toward the RFS2 standard. If this is the case, then our FRM analysis will be adjusted to reflect this.

In addition to MSW and C&D waste generated from normal day-to-day activities, there is also potential for renewable biomass to be generated from natural disasters. This includes diseased trees, other woody debris, and C&D debris. For instance, Hurricane Katrina was estimated to have damaged approximately 320 million large trees.[96] Katrina also generated over 100 million tons of residential debris, not including the commercial sector. The material generated from these situations could potentially be used to generate cellulosic biofuel. While we acknowledge this material could provide a large source in the short-term, natural disasters are highly variable, making it hard to predict future volumes that could be generated. We seek comment on how to take into account such estimates to be included in future feedstock availability analyses.

ii. Agricultural and Forestry Residues

The next category of feedstocks chosen will likely be those that are readily produced but have not yet been commercially collected. This includes both agricultural and forestry residues.

Agricultural residues are expected to play an important role early on in the development of the cellulosic ethanol industry due to the fact that they are already being grown. Agricultural crop residues are biomass that remains in the field after the harvest of agricultural crops. The most common residue types include corn stover (the stalks, leaves, and/or cobs), straw from wheat, rice, barley, or oats, and bagasse from sugarcane. The eight leading U.S. crops produce more than 500 million tons of residues each year, although only a fraction can be used for fuel and/or energy production due to sustainability and conservation constraints.[97] Crop residues can be found all over the United States, but are primarily concentrated in the Midwest since corn stover accounts for half of all available agricultural residues.

Agricultural residues play an important role in maintaining and improving soil quality, protecting the soil surface from water and wind erosion, helping to maintain nutrient levels, and protecting water quality. Thus, collection and removal of agricultural residues must take into account concerns about the potential for increased erosion, reduced crop productivity, depletion of soil carbon and nutrients, and water pollution. Sustainable removal rates for agricultural residues have been estimated in various studies, many showing tremendous variability due to local differences in soil and erosion conditions, soil type, landscape (slope), tillage practices, crop rotation managements, and the use of cover crops. One of the most recent studies by top experts in the field showed that under current rotation and tillage practices, about 30% of stover (about 59 million metric tons) produced in the U.S. could be collected, taking into consideration erosion, soil moisture concerns, and nutrient replacement costs.[98] The same study showed that if farmers chose to convert to no-till corn management and total stover production did not change, then approximately 50% of stover (100 million metric tons) could be collected without causing erosion to exceed the tolerable soil loss. This study, however, did not consider possible soil carbon loss which other studies indicate may be a greater constraint to environmentally sustainable feedstock harvest than that needed to control water and wind erosion.[99] Experts agree that additional studies are needed to further evaluate how soil carbon and other factors affect sustainable removal rates. Despite unclear guidelines for sustainable removal rates due to the uncertainties explained above, our agricultural modeling analysis assumes that 0% of stover is removable for conventional tilled lands, 35% of stover is removable for conservation tilled lands, and 50% is removable for no-till lands. In general, these removal guidelines are appropriate only for the Midwest, where the majority of corn is currently grown.

As already noted, removal rates will vary within regions due to local differences. Given the current understanding of sustainable removal rates, we believe that such assumptions are reasonably justified. We invite comment on these assumptions. Based on our research we also note that residue maintenance requirements for the amount of biomass that must remain on the land to ensure soil quality is another approach for modeling sustainable residue collection quantities, therefore we also invite comment on this approach. This approach would likely be more accurate for all landscapes as site specific conditions such as soil type, topography, etc. could be taken into account. This would prevent site specific soil erosion and soil quality concerns that would inevitably exist when using average values for residue removal rates across all soils and landscapes. At the time of our analyses we had limited data on which to accurately apply this approach and therefore assumed the removal guidelines based on tillage practices. Refer to the Section 1.1 of the DRIA for more discussion on sustainable removal rates.

Some of the challenges of relying on agricultural residues to produce biofuels include the development of the technology and infrastructure for the harvesting of biomass crops. For example, it may be possible to reduce costs by harvesting the corn stover at the same time that the corn is harvested, in a single pass operation, as opposed to two separate harvests. In addition, because agricultural residues are usually harvested only one time per year, but cellulosic ethanol plants must receive the feedstock throughout the year, agricultural residues would likely need to be stored at a secondary storage facility. The transportation and storage issues and costs associated with this secondary storage will add additional costs to using agricultural residue as cellulosic plant feedstock. These significant transportation and storage issues need to be resolved and the infrastructure built before agricultural

[95] Assuming 90 gal/dry ton ethanol conversion yield for urban waste in 2022.

[96] Chambers, J., ''Hurricane Katrina's Carbon Footprint on U.S. Gulf Coast Forests'' *Science* Vol. 318, 2007.

[97] Elbehri, Aziz. USDA, ERS. ''An Evaluation of the Economics of Biomass Feedstocks: A Synthesis of the Literature. Prepared for the Biomass Research and Development Board,'' 2007; Since 2007, a final report has been released. Biomass Research and Development Board, ''The Economics of Biomass Feedstocks in the United States: A Review of the Literature,'' October 2008.

[98] Graham, R.L., ''Current and Potential U.S. Corn Stover Supplies,'' *American Society of Agronomy* 99:1–11, 2007.

[99] Wilhelm, W.W. *et. al.,* ''Corn Stover to Sustain Soil Organic Carbon Further Constrains Biomass Supply,'' *Agron. J.* 99:1665–1667, 2007.

residues can supply a steady stream of feedstock to the biorefinery. We discuss these harvesting and storage challenges in Section 1.3 of the DRIA.

Our agricultural modeling (FASOM) suggests that corn stover will make up the majority of agricultural residues used by 2022 to meet the EISA cellulosic biofuel standard (approximately 83 million dry tons used to produce 7.8 billion gallons of cellulosic ethanol).[100] Smaller contributions are expected to come from other crop residues, including bagasse (1.2 Bgal ethanol) and sweet sorghum pulp (0.1 Bgal ethanol).[101] At the time of this proposal, FASOM was able to model agricultural residues but not forestry biomass as potential feedstocks. As a result, we relied on USDA–Forest Service (FS) for information on the forestry sector.

The U.S. has vast amounts of forest resources that could potentially provide feedstock for the production of cellulosic biofuel. One of the major sources of woody biomass could come from logging residues. The U.S. timber industry harvests over 235 million dry tons annually and produces large volumes of non-merchantable wood and residues during the process.[102] Logging residues are produced in conventional harvest operations, forest management activities, and clearing operations. In 2004, these operations generated approximately 67 million dry tons/year of forest residues that were left uncollected at harvest sites.[103] Other feedstocks include those from other removal residues, thinnings from timberland, and primary mill residues.

Harvesting of forestry residue and other woody material can be conducted throughout the year. Thus, unlike agricultural residue which must be moved to secondary storage, forest material could be ''stored on the stump.'' Avoiding the need for secondary storage and the transportation costs for moving the feedstock there potentially provides a significant cost advantage for forest residue over agricultural residue. This could allow forest residue to be transported from further distances away from the cellulosic plant compared to agricultural residue at the same feedstock price. Section 1.1 of the DRIA further details some of challenges with using forestry biomass as a feedstock.

EISA does not allow forestry material from national forests and virgin forests that could be used to produce biofuels to count towards the renewable fuels requirement under EISA. Therefore, we required forestry residue estimates that excluded such material. Most recently, the USDA–FS provided forestry biomass supply curves for various sources (i.e., logging residues, other removal residues, thinnings from timberland, etc.). This information suggested that a total of 76 million dry tons of forest material could be available for producing biofuels (excluding forest biomass material contained in national forests as required under EISA). However, much of the forest material is in small pockets of forest which because of its regional low density, could not help to justify the establishment of a cellulosic ethanol plant. After conducting our feedstock availability analysis, we estimated that approximately 44 million dry tons of forest material could be used, which would make up approximately one fourth, or 3.8 billion gallons, of the 16 billion gallons of cellulosic biofuel required to meet EISA.

iii Dedicated Energy Crops

While urban waste, agricultural residues, and forest residues will likely be the first feedstocks used in the production of cellulosic biofuel, there may be limitations to their use due to land availability and sustainable removal rates. Energy crops which are not yet grown commercially but have the potential for high yields and a series of environmental benefits could help provide additional feedstocks in the future. Dedicated energy crops are plant species grown specifically as renewable fuel feedstocks. Various perennial plants have been researched as potential dedicated feedstocks. These include switchgrass, mixed prairie grasses, hybrid poplar, miscanthus, and willow trees.

Perennials have several benefits over many major agricultural crops (the majority of which are annual plants). First, energy crops based on perennial species are grown from roots or rhizomes that remain in the soil after harvests. This reduces annual field preparation and fertilization costs. Second, perennial crops in temperate zones may also have significantly higher total biomass yield per unit of land area compared to annual species because of higher rates of net photosynthetic CO_2 fixation into sugars. Third, lower fertilizer runoff, lower soil erosion, and increased habitat diversity are also attributes that make perennial crops more attractive than annual crops.[104] Finally, energy crops tend to store more carbon in the soil compared to agricultural crops such as corn.[105]

The introduction of dedicated energy crops could present some potential risks, however. Dedicated energy crops for cellulosic biofuels can be non-native to the region where their production is proposed.[106] As a result, these species may potentially escape cultivation and damage surrounding ecosystems.[107] In addition breeding and genetic engineering to increase environmental tolerance, increase harvestable biomass production, and enhance energy conversion may have unexpected ecological consequences. To minimize such risks, non-native species and non-wild-type native species (i.e. native species after genetic modification) should be introduced in a responsible manner and evaluated carefully in order to weigh the potential risks against the benefits.

Currently, an energy crop receiving much attention is switchgrass. Switchgrass has many qualities that make it a prime cellulosic feedstock option. However, switchgrass and other energy crops are not currently harvested on a large scale. Switchgrass would likely be grown on a 10-year crop rotation basis, with harvest beginning in year 1 or 2, depending on location. Because switchgrass and other dedicated energy crops would not be harvested annually, there will be some economic challenges in terms of price forecasting and contracts. Accordingly, 10- to 15-year arrangements may be needed to stabilize the market for energy crops.[108] Despite these challenges, dedicated energy crops are still projected to be needed in 2022 in order to meet the aggressive goal of 16 Bgal of

[100] Assuming 94 gal/dry ton ethanol conversion yield for corn stover in 2022.

[101] Bagasse is a byproduct of sugarcane crushing and not technically an agricultural residue. Sweet sorghum pulp is also a byproduct of sweet sorghum processing. We have included it under this heading for simplification due to sugarcane being an agricultural feedstock.

[102] Smith, W. Brad *et. al.,* ''Forest Resources of the United States, 2002 General Technical Report NC–241,'' St. Paul, MN: U.S. Dept. of Agriculture, Forest Service, North Central Research Station, 2004.

[103] USDA–Forest Service. ''Timber Products Output Mapmaker Version 1.0.'' 2004.

[104] DOE., ''Breaking the Biological Barriers to Cellulosic Ethanol: A Joint Research Agenda,'' 2006.

[105] Tolbert, V.R., *et al.,* ''Biomass Crop Production: Benefits for Soil Quality and Carbon Sequestration,'' March 1999.

[106] Lewandowski, I., J. M. O. Scurlock, E. Lindvall, and M. Chistou, ''The development and current status of perennial rhizomatous grasses as energy crops in the U.S. and Europe,'' *Biomass Bioenergy* 25:335–361, 2003.

[107] The Council for Agricultural Science and Technology (CAST), ''Biofuel Feedstocks: The Risk of Future Invasions,'' CAST Commentary QTA2007–1. November 2007. Accessed at: *http://pdf.cast-science.org/websiteUploads/publicationPDFs/Biofuels%20Commentary%20Web%20version%20with%20color%20%207927146.pdf*

[108] Zeman, N., ''Feedstock: Potential Players,'' *Ethanol Producer Magazine,* October 2006.

cellulosic biofuel by 2022 as outlined in EISA.

Since energy crops are not being grown today to make fuels, their production and use depends on the development of a successful strategy. One issue is that if they were to be grown on farmland currently used to grow crops, the growth of switchgrass would have an opportunity cost associated with the loss of agricultural production. For this reason, energy crops may instead be grown on more marginal farm land such as fallow farmland and farmland which has been converted over to prairie grass. A study by Stanford and the Carnegie Institution found that 58 million hectares (145 million acres) of abandoned farmland would potentially be available for growing energy crops here in the U.S.[109] However, they also concluded that this land is marginal in quality and thus the production per acre would be much lower compared to prime farm land. Additionally, a substantial amount of this abandoned farm land is a part of the Conservation Reserve Program (CRP). The CRP is the U.S. Department of Agriculture's voluntary program that was established by the Food Security Act of 1985 to provide farmers with a dependable source of income, reduce erosion on unused farmland, and serve to preserve wildlife and water quality.[110] A large portion of the 36 million acres in the CRP land is currently planted with switchgrass and mixed prairie grasses.[111] However, the 2008 Farm Bill capped the number of CRP acres at 32 million acres for 2010–2012, and we expect that some of the CRP acres that are not re-enrolled will go into crop production. While it may be possible to use some of the CRP acres to produce biofuels from switchgrass and prairie grass, the potential loss of the wildlife habitat and water quality benefits of CRP land would have to be weighed against the potential use for this land for growing energy crops. Also, a significant portion of the CRP land is wetlands and likely could not be used for growing energy crops without impacting water quality and wildlife.

In addition to estimating the extent that agricultural residues might contribute to cellulosic ethanol production, FASOM also estimated the contribution that energy crops might provide.[112] FASOM covers all cropland and pastureland in production in the 48 conterminous United States, however it does not contain all categories of grassland and rangeland captured in USDA's Major Land Use data sets. Therefore, it is possible there is land appropriate for growing dedicated energy crops that is not currently modeled in FASOM. Furthermore, we constrained FASOM to be consistent with the 2008 Farm Bill and assumed 32 million acres would stay in CRP.[113] These constraints on land availability may have contributed to the model choosing a substantial amount of agricultural residues mostly as corn stover and a relatively small portion of energy crops as being economically viable feedstocks. The use of other models, such as USDA's Regional Environment and Agriculture Programming (REAP) model and University of Tennessee's POLYSYS model, have shown that the use of energy crops in order to meet EISA may be more significant than our current FASOM modeling results.[114] As such, we plan to revisit these land availability assumptions in order to arrive at a more consistent basis for the FRM. We request comment on these assumptions, in addition to all the cellulosic yield assumptions that are contained in DRIA Chapter 1.

iv. Summary of Cellulosic Feedstocks for 2022

Table V.B.2–4 summarizes our internal estimate of cellulosic feedstocks and their corresponding volume contribution to 16 billion gallons cellulosic biofuel by 2022 for the purposes of our impacts assessment.

TABLE V.B.2–4—CELLULOSIC FEEDSTOCKS ASSUMED TO MEET EISA IN 2022

Feedstock	Volume (Bgal)
Agricultural Residues	9.1
Corn Stover	7.8
Sugarcane Bagasse	1.2
Sweet Sorghum Pulp	0.1
Forestry Biomass	3.8
Urban Waste	2.2
Dedicated Energy Crops (Switchgrass)	0.9
Total	16.0

v. Cellulosic Plant Siting

Future cellulosic biofuel plant siting was based on the types of feedstocks that would be most economical as shown in Table V.B.2–4, above. As cellulosic biofuel refineries will likely be located close to biomass resources in order to take advantage of lower transportation costs, we've assessed the potential areas in the U.S. that grow the various feedstocks chosen. To do this, we used data on harvested acres by county for crops that are currently grown today, such as corn stover and sugarcane (for bagasse).[115] In some cases, crops are not currently grown, but have the potential to replace other crops or pastureland (e.g. dedicated energy crops). We used the output from our economic modeling (FASOM) to help us determine which types of land are likely to be replaced by newly grown crops. For forestry biomass, USDA-Forestry Service provided supply curve data by county showing the available tons produced. Urban waste (MSW wood, paper, and C&D debris) was estimated to be located near large population centers.

Using feedstock availability data by county/city, we located potential cellulosic sites across the U.S. that could justify the construction of a cellulosic plant facility. For more details on this analysis, refer to Section 1.5 of the DRIA. Table V.B.2–5 shows the volume of cellulosic facilities by feedstock by state projected for 2022. The total volumes given in Table V.B.2–5 match the total volumes given in Table V.B.2–4 within a couple hundred million gallons. As these differences are relatively small, we believe the cellulosic facilities sited are a good estimate of potential locations.

[109] Campbell, J.E. *at al.,* ''The global potential of bioenergy on abandoned agriculture lands,'' *Environ. Sci. Technology,* 2008.

[110] Charles, Dan; ''The CRP: Paying Farmers not to Farm,'' National Public Radio, May 5, 2008.

[111] Farm Service Agency, ''Conservation Reserve Program, Summary and Enrollment Statistics FY2006,'' May 2007.

[112] Assuming 16 Bgal cellulosic biofuel total, 2.2 Bgal from Urban Waste, and 3.8 Bgal from Forestry Biomass; 10 Bgal of cellulosic biofuel for ag residues and/or energy crops would be needed.

[113] Beside the economic incentive of a farmer payment to keep land in CRP, local environmental interests may also fight to maintain CRP land for wildlife preservation. Also, we did not know what portion of the CRP is wetlands which likely could not support harvesting equipment.

[114] Biomass Research and Development Initiative (BR&DI), ''Increasing Feedstock Production for Biofuels: Economic Drivers, Environmental Implications, and the Role of Research,'' *http://www.brdisolutions.com* December 2008.

[115] NASS database. *http://www.nass.usda.gov/.*

TABLE V.B.2–5—PROJECTED CELLULOSIC ETHANOL VOLUMES BY STATE

[Million gallons in 2022]

State	Total volume	Agricultural residue volume	Energy crop volume	Urban waste volume	Forestry volume
Alabama	532	0	0	140	392
Arkansas	298	0	0	0	298
California	450	0	0	221	229
Colorado	28	0	0	28	0
Florida	421	390	0	31	0
Georgia	437	0	0	67	370
Illinois	1,525	1,270	0	198	58
Indiana	1,109	948	0	101	60
Iowa	1,697	1,635	0	32	30
Kansas	310	250	0	29	32
Kentucky	70	70	0	0	0
Louisiana	1,001	590	0	103	308
Maine	191	0	0	2	189
Michigan	505	283	0	171	51
Minnesota	876	750	0	50	76
Mississippi	214	0	0	22	192
Missouri	654	504	0	78	72
Montana	92	0	0	9	83
Nebraska	956	851	0	31	75
Nevada	17	0	0	17	0
New Hampshire	171	0	35	29	107
New York	72	0	0	72	0
North Carolina	315	0	0	98	217
Ohio	598	410	0	156	32
Oklahoma	793	0	777	0	16
Oregon	244	0	0	44	200
Pennsylvania	42	0	0	42	0
South Carolina	213	0	0	57	156
South Dakota	434	350	0	6	78
Tennessee	97	0	0	19	78
Texas	576	300	0	131	145
Virginia	197	0	0	95	102
Washington	175	0	0	17	158
West Virginia	149	0	101	0	48
Wisconsin	581	432	0	43	106
Total Volume	16,039	9,034	913	2,139	3,955

It is important to note, however, that there are many more factors other than feedstock availability to consider when eventually siting a plant. We have not taken into account, for example, water constraints, availability of permits, and sufficient personnel for specific locations. As many of the corn stover facilities are projected to be located close to corn starch facilities, there is the potential for competition for clean water supplies. Therefore, as more and more facilities draw on limited resources, it may become apparent that various locations are infeasible. Nevertheless, our plant siting analysis provides a reasonable approximation for analysis purposes since it is not intended to predict precisely where actual plants will be located. Other work is currently being done that will help address some of these issues, but at the time of this proposal, was not yet available.[116]

As we are projecting the location of cellulosic plants in 2022, it is important to keep in mind the various uncertainties in the analysis. For example, future analyses could determine better recommendations for sustainable removal rates. In the case where lower removal rates are recommended, agricultural residues may be more limited and could require more growth in dedicated energy crops. Also, the feedstocks could be processed in the field to a liquid by a pyrolysis process, facilitating the ability to ship the preprocessed biomass to plants located further away from the feedstock source. Given the information we have to date, we believe our projected locations for cellulosic facilities represent a reasonable forecast for estimating the impacts of this rule.

3. Imported Ethanol

a. Historic World Ethanol Production and Consumption

Although ethanol can be used for multiple purposes (fuel, industrial, and beverage), fuel ethanol is by far the largest market, accounting for about two-thirds of the total world ethanol consumed. According to forecasts, fuel ethanol might even exceed 80% of the market share by the end of the decade.[117] In 2008, the top three fuel ethanol producers were the U.S., Brazil, and the European Union (EU), producing 9.0, 6.5, and 0.7 billion gallons, respectively.[118] Other countries that have produced ethanol include

[116] USDA, WGA, Bioenergy Strategic Assessment project findings upcoming as noted in report WGA. Transportation Fuels for the Future Biofuels: Part I. 2008.

[117] F.O. Licht., ''World Ethanol Markets: The Outlook to 2015'', 2006, pg. 21.

[118] Renewable Fuels Association (RFA), ''2007 World Fuel Ethanol Production,'' *http://www.ethanolrfa.org/industry/statistics/#E*, March 31, 2009.

China, Canada, Thailand, Colombia, and India.

Consumption of fuel ethanol, like production, is also dominated by the United States and Brazil. The U.S. dominates world fuel ethanol consumption, with 9.6 billion gallons consumed in 2008 (domestic production plus imports).[119] Brazil is second in consumption, with about 4.9 billion gallons projected to be consumed in 2007/2008.[120] The EU is also a significant consumer of ethanol; however, consumption for the EU countries was only approximately 0.7 billion gallons in 2007.[121]

b. Historic/Current Domestic Imports

Ethanol imports have traditionally played a relatively small role in the U.S. transportation fuel market due to historically low crude prices and the tariff on imported ethanol. While low crude prices made it difficult for both domestic and imported ethanol to compete with gasoline, the addition of the federal excise tax credit made it possible for domestic ethanol to be economically competitive.

Between 2000 and 2003, the total volume of fuel ethanol imports into the United States remained relatively stable at 46–68 million gallons.[122] During this period of time, mostly Brazilian-based ethanol entered the U.S. primarily through the Caribbean Basin Initiative (CBI) countries where it could avoid the tariff. From 2004–2005, with rising crude oil prices, most estimates show U.S. fuel ethanol imports increased slightly to 135–164 million gallons, or about 4% of the total U.S. fuel ethanol consumption (3.5 to 4.0 billion gallons). The volume of imports rose dramatically in 2006 to 654–720 million gallons, or about 13% of the 2006 total ethanol consumption of 5.4 billion gallons. The largest volume of imports in 2006 was from direct Brazilian imports. This increase in ethanol imports was mainly due to the withdrawal of MTBE from the fuel pool which increased the price of ethanol. MTBE was used in gasoline to fulfill the oxygenate requirements set by Congress in the 1990 Clean Air Act Amendments. EPAct further accelerated the withdrawal of MTBE because gasoline marketers were no longer required to use an oxygenate and gasoline marketers did not receive the MTBE liability protection that they had petitioned for. Refiners responded by removing MTBE and replacing its use with ethanol. As a result, the demand for ethanol increased at unprecedented rates as most refiners replaced MTBE with ethanol. The dramatic increase in crude oil costs at this time also made ethanol more economical by comparison.

By the end of 2006, almost all MTBE was phased out of gasoline. However, crude oil prices remained high, allowing ethanol imports to the U.S. to remain economical in comparison to the past. Although not as high as the volume of ethanol imported in 2006, the U.S. continued to import ethanol in 2007 (425–450 million gallons). In 2008, the U.S. imported 519–556 million gallons.[123] As the data show, the volume of imported ethanol can fluctuate greatly. By looking at historical import data it is difficult to project the potential volume of future imports to the U.S. Rather, it is necessary to assess future import potential by analyzing the major players for foreign biofuels production and consumption.

c. Projected Domestic Imports

In our assessment of foreign ethanol production and consumption, we analyzed the following countries or group of countries: Brazil, the EU, Japan, India, and China. Our analyses indicate that Brazil would likely be the only nation able to supply any meaningful amount of ethanol to the U.S. in the future. Depending on whether the mandates and goals of the EU, Japan, India, and China are enacted or met in the future, it is likely that this group of countries would consume any growth in their own production and be net importers of ethanol, thus competing with the U.S. for Brazilian ethanol exports.

Brazil is expected to supply the majority of future ethanol demand and to expand their capacity for several reasons. First, Brazil has over 30 years experience in developing the research and technologies for producing sugarcane ethanol. As a result, Brazilians have been able to improve agricultural and conversion processes so that sugarcane ethanol is currently the least costly method for producing biofuels. See Section VIII for further discussion on the production costs for sugarcane ethanol.

Second, it is believed that domestic demand for ethanol in Brazil will begin to slow as most of the national fleet of vehicles will have transitioned to flex-fuel within the next few years.[124] Thus, as domestic demand begins to level off, some experts see a significant possibility that exports will become more relevant in market share terms.

Lastly, Brazil has large land areas for potential expansion for sugarcane. A study commissioned by the Brazilian government produced an analysis in which Brazil's arable land was evaluated for its suitability for cane.[125] Setting aside areas protected by environmental regulations and those with a slope greater than 12% (those not suitable for mechanized farming), tripling ethanol production (a goal set by the Brazilian government by 2020) would require only an additional 14 million acres. This additional acreage would only be about 2% of suitable land for sugarcane production. Refer to Section 1.5 of the DRIA for more details.

Although Brazil is in an excellent position to help meet the growing global demand for ethanol, several constraints could limit the expansion of ethanol production. As Brazil's government has adopted plans to meet global demand by tripling production by 2020,[126] this would mean a total capacity of about 12.7 billion gallons, to be achieved through a combination of efficiency gains, greenfield projects, and infrastructure expansions. Estimates for the investment required tend to range from $2 to $4 billion a year.[127] In addition, Brazil will need to improve its current ethanol infrastructure (i.e. improvements in power, transportation, storage, distribution logistics, and communications). It is estimated that Brazil will need to invest $1 billion each year for the next 15 years in infrastructure to keep pace with capacity expansion and export demand.[128] Refer to Section 1.5 of the DRIA for further details on the improvements needed for Brazil to increase ethanol production capacity.

Due to uncertainties in the future demand for ethanol domestically and internationally as well as uncertainties in the actual investments made in the Brazilian ethanol industry, there appears to be a wide range of Brazilian production and domestic consumption estimates. The most current and complete estimates indicate that total

[119] *Ibid.*

[120] UNICA, ''Sugarcane Industry in Brazil: Ethanol Sugar, Bioelectricity'' Brochure, 2008.

[121] European Bioethanol Fuel Association (eBio), ''The EU Market: Production and Consumption,'' *http://www.ebio.org/EUmarket.php*, March 31, 2009.

[122] Values given report USITC and RFA data, however, EIA reports slightly lower numbers prior to 2004.

[123] USITC and EIA import data reported.

[124] Agra FNP, ''Sugar and Ethanol in Brazil: A Study of the Brazilian Sugar Cane, Sugar and Ethanol Industries,'' 2007.

[125] CGEE, ABDI, Unicamp, and NIPE, Scaling Up the Ethanol Program in Brazil, n.d. as quoted in Rothkopf, Garten, ''A Blueprint for Green Energy in the Americas,'' 2006.

[126] Rothkopf, Garten, ''A Blueprint for Green Energy in the Americas,'' 2006.

[127] *Ibid.*

[128] *Ibid.*

Brazilian ethanol exports will likely reach 3.8–4.2 billion gallons by 2022.[129] [130] [131] As this volume of ethanol export is available to countries around the world, only a portion of this will be available exclusively to the United States. If the balance of the EISA advanced biofuel requirement not met with cellulosic biofuel and biomass-based diesel were to be met with imported sugarcane ethanol alone, it would require 3.2 billion gallons (*see* Table V.A.2–1), or approximately 80% of total Brazilian ethanol export estimates.

The amount of Brazilian ethanol available for shipment to the U.S. will be dependent on the biofuels mandates and goals set by other foreign countries (i.e., the EU, Japan, India, and China) in addition to U.S. policies to promote the use of renewable fuels. Our estimates show that there could be a potential demand for imported ethanol of 4.6–14.6 billion gallons by 2020/2022 from these countries. This is due to the fact that some countries are unable to produce large volumes of ethanol because of land constraints or low production capacity. As such, foreign countries may have limited domestic biofuel production capability and may therefore require importation of biofuels in order to meet their mandates and goals. Refer to Section 1.5 of the DRIA for further details. Therefore, if other foreign country mandates and goals are to be met, then Brazil may need to either increase production much more than its government projects or export less ethanol to the U.S. This suggests that the U.S. may be competing for Brazilian ethanol exports if supplies are limited in the future. For our analysis we assumed that the U.S. would consume the majority of Brazilian exports (i.e. 80% of export estimates in 2022). This is aggressive, yet within the bounds of reason, therefore, we have made this simplifying assumption for the purposes of further analysis. We seek comment on the legitimacy of this assumption given the ethanol export deals and commitments that Brazil has made or may potentially make with other nations in the future.

[129] EPE, ''Plano Nacional de Energia 2030,'' Presentation from Mauricio Tolmasquim, 2007.

[130] UNICA, ''Sugarcane Industry in Brazil: Ethanol, Sugar, Bioelectricity,'' 2008.

[131] USEPA International Visitors Program Meeting October 30, 2007, correspondence with Mr. Rodrigues, Technical Director from UNICA Sao Paulo Sugarcane Agro-industry Union, stated approximately 3.7 billion gallons probable by 2017/2020; Consistent with brochure ''Sugarcane Industry in Brazil: Ethanol Sugar, Bioelectricity'' from UNICA (3.25 Bgal export in 2015 and 4.15 Bgal export in 2020).

Generally speaking, Brazilian ethanol exporters will seek routes to countries with the lowest transportation costs, taxes, and tariffs. With respect to the U.S., the most likely route is through the Caribbean Basin Initiative (CBI).[132] Brazilian ethanol entering the U.S. through the CBI countries is not currently subject to the 54 cent imported ethanol tariff and yet receives the 45 cent ethanol blender tax subsidy. Due to the economic incentive of transporting ethanol through the CBI, we expect the majority of the tariff rate quota (TRQ) to be met or exceeded, perhaps 90% or more. The TRQ is set each year as 7% of the total domestic ethanol consumed in the prior year. If we assume that 90% of the TRQ is met and that total domestic ethanol (corn and cellulosic ethanol) consumed in the prior year was 28.5 Bgal, then approximately 1.8 Bgal of ethanol could enter the U.S. through CBI countries. The rest of the Brazilian ethanol exports not entering the CBI will compete on the open market with the rest of the world demanding some portion of direct Brazilian ethanol. We calculated the amount of direct Brazilian ethanol exports in 2022 to the U.S. as the total imported ethanol required (3.14 billion gallons) to meet the RFS2 volume requirements subtracted by imported ethanol from CBI countries (1.8 billion gallons), or equal to 1.34 billion gallons.

In the past, companies have also avoided the ethanol import tariff through a duty drawback.[133] The drawback is a loophole in the tax rules which allowed companies to import ethanol and then receive a rebate on taxes paid on the ethanol when jet fuel is sold for export within three years. The drawback considered ethanol and jet fuel as similar commodities (finished petroleum derivatives).[134] [135] Most recently, however, Senate Representative Charles Grassley from Iowa included a provision into the Farm Bill of 2008 that ended such refunds. The provision states that ''any duty paid under subheading 9901.00.50 of the Harmonized Tariff Schedule of the United States on imports of ethyl alcohol or a mixture of ethyl alcohol may not be refunded if the exported article upon which a drawback claim is based does not contain ethyl alcohol or a mixture of ethyl alcohol.'' [136] The provision is effective on or after October 1, 2008 and companies have until October 1, 2010 to apply for a duty drawback on prior transactions. With the loophole closed, it is anticipated that there may be less ethanol directly exported from Brazil in the future.[137]

[132] Other preferential trade agreements include the North American Free Trade Agreement (NAFTA) which permits tariff-free ethanol imports from Canada and Mexico and the Andean Trade Promotion and Drug Eradication Act (ATPDEA) which allows the countries of Columbia, Ecuador, Bolivia, and Peru to import ethanol duty-free. Currently, these countries export or produce relatively small amounts of ethanol, and thus we have not assumed that the U.S. will receive any substantial amounts from these countries in the future for our analyses.

[133] Rapoza, Kenneth, ''UPDATE: Tax Loophole Helps US Import Ethanol 'Duty Free'—ED&F,'' *INO News, Dow Jones Newswires,* March 2008. *http://news.ino.com/.*

[134] Peter Rhode, ''Senate Finance May Take Up Drawback Loophole As Part of Energy Bill,'' *EnergyWashington Week,* April 18, 2007. As sited in Yacobucci, Brent, ''Ethanol Imports and the Caribbean Basin Initiative,'' CRS Report for Congress, Order Code RS21930, Updated March 18, 2008.

[135] Perkins, Jerry, ''BRAZIL: Loophole Hurt U.S. Ethanol Prices,'' *DesMoinesRegister.com,* October 18, 2007.

For our distribution and air quality analyses, we had to make a determination as to where the projected imported ethanol would likely enter the United States. To do so, we started by looking at 2006 ethanol import data and made assumptions as to which countries would likely contribute to the CBI ethanol volumes in Table V.B.3–1, and to what extent.[138] We estimated that, on average, in future years, 30% would come from Jamaica, 20% each would come from El Salvador and Costa Rica, and 15% each would originate from Trinidad & Tobago and the Virgin Islands. Even though to date there have not been a lot of ethanol imports from the Virgin Islands, we believe that they could become a comparable importer to Trinidad & Tobago in the future under the proposed RFS2 program.

From there, we looked at 2006–2007 import data and estimated the general destination of Brazilian ethanol and the five contributing CBI countries' domestic imports. Based on these countries' geographic locations and import histories, we estimated that in 2022 about 75% of the ethanol would be imported to the East and Gulf Coasts and the remainder would go to the West Coast and Hawaii. To estimate import locations, we considered coastal port cities that had received ethanol or finished gasoline imports in 2006 and distributed the ethanol accordingly based on ethanol demand. For more information on this analysis, refer to Section 1.5 of the DRIA.

[136] Public Law Version 6124 of the Farm Bill. 2008. *http://www.usda.gov/documents/Bill_6124.pdf.*

[137] Lundell, Drake, ''Brazilian Ethanol Export Surge to End; U.S. Customs Loophole Closed Oct. 1,'' Ethanol and Biodiesel News, Issue 45, November 4, 2008.

[138] Source: EIA data on company-level imports (*http://www.eia.doe.gov/oil_gas/petroleum/data_publications/company_level_imports/cli_historical.html*).

4. Biodiesel & Renewable Diesel

Biodiesel and renewable diesel are replacements for petroleum diesel that are made from plant or animal fats. Biodiesel consists of fatty acid methyl esters (FAME) and can be used in low-concentration blends in most types of diesel engines and other combustion equipment with no modifications. The term renewable diesel covers fuels made by hydrotreating plant or animal fats in processes similar to those used in refining petroleum. Renewable diesel is chemically analogous to blendstocks already used in petroleum diesel, thus its use can be transparent and its blend level essentially unlimited. The goal of both biodiesel and renewable diesel conversion processes is to change the properties of a variety of feedstocks to more closely match those of petroleum diesel (such as its density, viscosity, and energy content) for which the engines and distribution system have been designed. Both processes can produce suitable fuels from biogenic sources, though we believe some feedstocks lend themselves better to one process or the other. The definition of biodiesel given in applicable regulations is sufficiently broad to be inclusive of both fuels.[139] However, the EISA stipulates that renewable diesel that is co-processed with petroleum diesel cannot be counted as ''biomass-based diesel'' for purposes of complying with its volume mandates.[140]

In general, plant and animal oils are valuable commodities with many uses other than transportation fuel. Therefore we expect the primary limiting factor in the supply of both biodiesel and renewable diesel to be feedstock availability and price. Expansion of their market volumes is dependent on being able to compete on price with the petroleum diesel they are displacing, which will depend largely on continuation of current subsidies and other incentives.

Other biomass-based diesel fuel plants are either already built or being considered for construction. Cello Energy has already started up a 20 million gallon per year catalytic depolymerization plant that is producing diesel fuel from cellulose and other feedstocks, and Cello intends on building several 50 million gallon per year plants to be started up in 2010. Also, numerous other companies are planning on building biomass to liquids (BTL) plants that produce diesel fuel through the syngas and Fischer Tropsch pathway. However, for our analysis for this proposed rulemaking, we did not project that biomass-based diesel fuel would be produced from these processes.

a. Historic and Projected Production

i. Biodiesel

As of September 2008, the aggregate production capacity of biodiesel plants in the U.S. was estimated at 2.6 billion gallons per year across approximately 176 facilities.[141] Biodiesel plants exist in nearly all states, with the largest density of plants in the Midwest and Southeast where agricultural feedstocks are most plentiful.

Table V.B.4–1 gives U.S. biodiesel production capacity, sales, and capacity utilization in recent years. The figures suggest that the industry has grown out of proportion with actual biodiesel demand. Reasons for this include various state incentives to build plants, along with state and federal incentives to blend biodiesel, which have given rise to an optimistic industry outlook over the past several years. Since the cost of capital is relatively low for the biodiesel production process (typically four to six percent of the total per-gallon cost), this industry developed a more grassroots profile in comparison to the ethanol industry, and, with median size less than 10 million gallons/yr, consists of a large number of small plants.[142] These small plants, with relatively low operating costs other than feedstock, have generally been able to survive producing below their nameplate capacities.

TABLE V.B.4–1—U.S. BIODIESEL CAPACITY AND PRODUCTION VOLUMES

[Million gallons][143]

Year	Capacity	Production	Utilization (percent)
2003	150	21	14%
2004	245	36	15
2005	395	115	29
2006	792	241	30
2007	1,809	499	28
2008	2,610	700	27

Some of this industry capacity may not be dedicated specifically to fuel production, instead being used to make oleochemical feedstocks for further conversion into products such as surfactants, lubricants, and soaps. These products do not show up in renewable fuel sales figures.

In 2004–5, demand for biodiesel grew rapidly, but the trend of increasing capacity utilization was quickly overwhelmed by additional plant starts. Since then, high commodity prices followed by reduced demand for transportation fuel have caused additional economic strain beyond the overcapacity situation. According to a survey conducted by Biodiesel Magazine staff, more than 1 in 5 plants were already idle or defunct as of late 2007 (though this likely varies by

[139] *See* Section 1515 of the Energy Policy Act of 2005. More discussion of the definitions of biodiesel and renewable diesel are given in the preamble of the Renewable Fuel Standard rulemaking, Section III.B.2, as published in the **Federal Register** Vol. 72, No. 83, p. 23917.

[140] For more detailed discussion of the definition of coprocessing and its implications for compliance with EISA, see Section III.B.1 of this preamble.

[141] Figures here were taken from National Biodiesel Board fact sheet dated September 29, 2008 (*http://biodiesel.org/pdf_files/fuelfactsheets/Producers%20Map%20-%20existing.pdf*). This information was current at the time these analyses were being done. More recent data maintained by Biodiesel Magazine suggests that by April 2009 the industry had contracted to approximately 137 plants with aggregate capacity of 2.3 billion gal/yr (*see http://www.biodieselmagazine.com/plant-list.jsp*).

[142] Capital figures derived from USDA production cost models. A publication describing USDA modeling of biodiesel production costs can be found in Bioresource Technology 97(2006) 671–8.

[143] Capacity data taken from National Biodiesel Board. Production figures taken from F.O. Licht World Ethanol and Biofuels Report, vol. 6, no. 11, p S271, except 2008, which is an estimate taken from National Biodiesel Board (*http://www.biodiesel.org/pdf_files/fuelfactsheets/Production_graph_slide.pdf*).

region).[144] A significant portion of the 2007 and 2008 production was exported to Europe or Asia where fuel prices and additional tax subsidies on top of those provided in the U.S. help cover transportation overseas and offset high feedstock costs. The Energy Information Administration is beginning to collect data on biodiesel imports and exports, but reports are not expected until later in 2009. Therefore precise figures are not available on what fraction of production was consumed domestically, but sources familiar with the industry suggest exports may have been as much as 200 million gallons in 2007 and likely more in 2008.[145] We do not account for any biodiesel exports in our analysis, though there will be sufficient plant capacity to produce material beyond the volumes required in the EISA should an export market exist.

To perform our distribution and emission impacts analyses for this proposal, it was necessary to forecast the state of the biodiesel industry in the timeframe of the fully-phased-in RFS. In general, this consisted of reducing the over-capacity to be much closer to the amount demanded, which we assumed to be equal to the requirement under the EISA given uncertainties about feedstock prices and changes in tax incentives in the long term. This was accomplished by considering as screening factors the current production and sales incentives in each state as well as each plant's primary feedstock type and whether it was BQ–9000 certified.[146] Going forward producers will compete for feedstocks and markets will consolidate. During this period the number of operating plants is expected to shrink, with surviving plants adding feedstock segregation and pre-treatment capabilities, giving them flexibility to process any mix of feedstocks available in their area. By the end of this period we project a mix of large regional plants and some smaller plants taking advantage of local market niches, with an overall average capacity utilization around 80% for dedicated fuel plants. Table V.B.4–2 summarizes this forecast. See Section 1.5.4 of the DRIA for more details.

TABLE V.B.4–2—SUMMARY OF PROJECTED BIODIESEL INDUSTRY CHARACTERIZATION USED IN OUR ANALYSES [147]

	2008	2022
Total production capacity on-line (million gal/yr)	2,610	1,050
Number of operating plants	176	35
Median plant size (million gal/yr)	5	30
Total biodiesel production (million gal)	700	810
Average plant utilization	0.27	0.77

ii. Renewable Diesel

Renewable diesel is a fuel (or blendstock) produced from animal fats, vegetable oils, and waste greases using chemical processes similar to those employed in petroleum hydrotreating. These processes remove oxygen and saturate olefins, converting the triglycerides and fatty acids into paraffins. Renewable diesel typically has higher cetane, lower nitrogen, and lower aromatics than petroleum diesel fuel, while also meeting stringent sulfur standards.

In comparison to biodiesel, renewable diesel has improved storage, stability, and shipping properties as a result of the oxygen and olefins in the feedstock being removed. This allows renewable diesel fuel to be shipped in existing petroleum pipelines used for transporting fuels, thus avoiding one significant issue with distribution of biodiesel. For more on fuel distribution, refer to Section V.C.

Considering that this industry is still in development and that there are no long-term projections of production volume, we base our production estimates primarily on the potential volume of feedstocks for this process, in the context of recent industry project announcements involving proven technology. We project that approximately two-thirds of renewable diesel will be produced at existing petroleum refineries, and half will be co-processed with petroleum (thus prohibiting it from counting as ''biomass-based diesel'' under the EISA). Tables V.B.4–3 and V.B.4–4 summarize these volumes.

TABLE V.B.4–3—PROJECTED RENEWABLE DIESEL VOLUMES BY PRODUCTION CATEGORY

[Million gallons in 2022]

	Existing facility	New facility
Co-processed with petroleum	188	—
Not co-processed with petroleum	63	125

b. Feedstock Availability

The primary feedstock for domestic biodiesel production has historically been soybean oil, with other plant and animal fats as well as recycled greases making up a smaller but significant portion of the biodiesel pool. Agricultural commodity modeling we have done for this proposal (*see* Section IX.A) suggests that soybean oil production will stay relatively flat in the future, causing supplies to tighten and prices to rise as demand increases for biofuels and food uses worldwide. The output of these models suggests that domestic soy oil production could support about 550 million gallons per year in 2022. This material is most likely to be processed by biodiesel plants due to the large available capacity of these facilities and their proximity to soybean production. Compared to other feedstocks, virgin plant oils are more easily processed into biofuel via simple transesterification due to their homogeneity of composition and lack of contaminants.

Another source of feedstock which could provide increasing and significant volume is oil extracted from corn or its co-products in the dry mill ethanol production process. Sometimes referred to as corn fractionation or dry separation, these processes get additional products of value from the dry milling process. This idea is not

[144] Derived from figures published in Biodiesel Magazine, May 2008, p. 39.

[145] Staff-level communication with National Biodiesel Board (April 2008).

[146] Information on state incentives was taken from U.S. Department of Energy Web site, accessed July 30, 2008, at *http://www.eere.energy.gov/afdc/fuels/biodiesel_laws.html*. Information on feedstock and BQ–9000 status was taken from Biodiesel Board fact sheet, accessed July 30, 2008, at *http://biodiesel.org/pdf_files/fuelfactsheets/Producers%20Map%20-%20existing.pdf*.

[147] Industry data for 2008 taken from National Biodiesel Board fact sheets at *http://www.biodiesel.org/buyingbiodiesel/producers_marketers/Producers%20Map-Existing.pdf* and *http://www.biodiesel.org/pdf_files/fuelfactsheets/Production_graph_slide.pdf* (both accessed April 27, 2009).

new, as existing wet mill plants create several product streams from their corn input, including oil. Corn fractionation can be seen as a way to get some of this added value without incurring the larger capital costs and potentially lower ethanol yields associated with wet mill plants. More detailed discussion of these processes and how they affect the co-product stream(s) can be found in DRIA Section 1.4.1.3.

The corn oil process on which we have chosen to focus for cost and volume estimates in this proposal is one that extracts oil from the thin stillage after fermentation (the non-ethanol liquid material that typically becomes part of distillers' grains with solubles). We believe installation of this type of equipment will be attractive to industry because it can be added onto an existing dry mill plant and does not impact ethanol yields since it does not process the corn prior to fermentation. Depending on the configuration, such a system can extract 20–50% of the oil from the co-product streams, and produces a distressed corn oil (non-food-grade, with some free fatty acids and/or oxidation by-products) product stream which can be used as feedstock by biodiesel facilities. Since it offers another stream of revenue, we believe it is reasonable to expect about 40% of projected total ethanol production to implement some type of oil extraction process by 2022, generating approximately 150 million gallons per year of corn oil biofuel feedstock.[148] We expect this material to be processed in biodiesel plants.

Rendered animal fats and reclaimed cooking oils and greases are another potentially significant source of biodiesel feedstock. We estimate that just two to four percent of biodiesel in 2007 was produced from waste cooking oils and greases, though this number is likely higher more recently.[149] Tyson Foods, in joint efforts with ConocoPhilips and Syntroleum, announced construction plans in 2008 for renewable diesel production facilities to begin operating in 2010 and producing up to 175 million gallons annually (combined capacity). By the end of our projection period, as much as 30% of rendered fats and waste grease could be converted to biofuel while still supporting production of pet food, soaps and detergents, and other oleochemicals.[150] We request comment from members of these industries on any potential impacts of diversion of rendered materials to biofuel.

Under this assumption, this material could make approximately 500 million gallons of biofuel (though we have not chosen to allocate all of it in our analyses here). We estimate this type of material could be most economically made into renewable diesel in the long term, as that process does not have the same sensitivities to free fatty acids and other contaminates typically present in waste greases as the biodiesel process; however, some amount of this material may continue to be processed in biodiesel plants that have acid pretreatment capabilities where it makes economic sense. Recent market shifts and changes in tax subsidies enacted after analyses were done for this NPRM have affected the relative economics of using waste fats and greases for biodiesel versus renewable diesel. We will reevaluate our assumptions in the FRM.

Our analysis of the countries with the most potential to produce and consume biodiesel in the future suggests that supplies of finished biodiesel will be tight, and prices of its feedstocks will remain high. Supplies to the U.S. will be limited by biofuel mandates and targets of other countries, preferential shipment of biodiesel to European and Asian nations, and the speed at which non-traditional crops such as jatropha can be developed. Thus, we cannot at this time project more than negligible amounts of biodiesel or its feedstocks being available for import into the U.S. in the future. For more discussion of international movement of biodiesel and its feedstocks, refer to Section 1.1 of the DRIA.

Table V.B.4–4 shows the projected potential contribution of these sources we have chosen to quantify. Other potential, but less certain, sources for biodiesel feedstocks include conversion of some existing croplands used for soybeans to higher-yielding oilseed crops. Production of oil from algae farms is also being investigated by a number of companies and universities as a source of biofuel feedstock. For additional discussion of such sources, refer to Section 1.1 of the DRIA.

TABLE V.B.4–4—ESTIMATED POTENTIAL BIODIESEL AND RENEWABLE DIESEL VOLUMES IN 2022

[Million gallons of fuel]

	Biomass-based diesel		Other advanced biofuel
	Biodiesel	Renewable diesel	Renewable diesel
Virgin plant oils	660	—	—
Corn fractionation	150	—	—
Rendered fats and greases	—	188	188

C. Renewable Fuel Distribution

The following discussion pertains to the distribution of biofuels. A discussion of the distribution of biofuel feedstocks and co-products is contained in Section 1.3.3 and 5.1 of the DRIA respectively. In conducting our analysis of biofuel distribution, we took into account the projected size and location of biofuel production facilities and where we project biofuels would be used.[151]

The current motor fuel distribution infrastructure has been optimized to facilitate the movement of petroleum-based fuels. Consequently, there are very efficient pipeline-terminal networks that move large volumes of petroleum-based fuels from production/import centers on the Gulf Coast and the Northeast into the heartland of the

[148] *See* Table 3 in Mueller, Steffen. An analysis of the projected energy use of future dry mill corn ethanol plants (2010–2030). October 10, 2007. Available at *http://www.chpcentermw.org/pdfs/2007CornEthanolEnergySys.pdf.*

[149] Based on plant capacities reported by the National Biodiesel Board and data reported by F.O. Licht.

[150] Based on statements from the National Renderer's Association.

[151] The location of biofuel production facilities and where biofuels would be used is discussed in Sections 1.5 and 1.7 of the DRIA respectively and earlier in this Section V of the preamble.

country. In contrast, the majority of renewable fuel is expected to be produced in the heartland of the country and will need to be shipped to the coasts, flowing roughly in the opposite direction of petroleum-based fuels. This limits the ability of renewable fuels to utilize the existing fuel distribution infrastructure.

The modes of distributing renewable fuels to the end user vary depending on constraints arising from their physical/chemical nature and their point of origination. Some fuels are compatible with the existing fuel distribution system, while others currently require segregation from other fuels. The location of renewable fuel production plants is also often dictated by the need to be close to the source of the feedstocks used rather than to fuel demand centers or to take advantage of the existing petroleum product distribution system. Hence, the distribution of renewable fuels raises unique concerns and in many instances requires the addition of new transportation, storage, blending, and retail equipment.

Significant challenges must be faced in reconfiguring the distribution system to accommodate the large volumes of ethanol and to a lesser extent biodiesel that we project will be used. While some uncertainties remain, particularly with respect to the ability of the market to support the use of the volume of E85 needed, no technical barriers appear to be insurmountable. The response of the transportation system to date to the unprecedented increase in ethanol use is encouraging. A U.S. Department of Agriculture (USDA) report concluded that logistical concerns have not hampered the growth in ethanol production, but that concerns may arise about the adequacy of transportation infrastructure as the growth in ethanol production continues.[152]

Considerable efforts are underway by individual companies in the fuel distribution system, consortiums of such companies, industry associations, independent study groups, and inter-agency governmental organizations to evaluate what steps may be necessary to facilitate the necessary upgrades to the distribution system to support compliance with the RFS2 standards.[153] EPA will continue to participate/monitor these efforts as appropriate to keep abreast of potential problems in the biofuel distribution system which might interfere with the use of the volumes of biofuels that we project will be needed to comply with the RFS2 standards. The 2008 Farm Act (Title IX) requires USDA, DOE, DOT, and EPA to conduct a biofuels infrastructure study that will assess infrastructure needs, analyze alternative development approaches, and provide recommendations for specific infrastructure development actions to be taken.[154]

Considerations related to the distribution of ethanol, biodiesel, and renewable diesel are discussed in the following sections as well as the changes to each segment in the distribution system that would be needed to support the volumes of these biofuels that we project would be used to satisfy the RFS2 standards.[155] We request comments on the challenges that will be faced by the fuel distribution system under the RFS2 standards and on what steps will be necessary to facilitate making the necessary accommodations in a timely fashion.[156]

To the extent that biofuels other than ethanol and biodiesel are produced in response to the RFS2 standards, this might lessen the need for added segregation during distribution. Distillate fuel produced from cellulosic feedstocks might be treated as petroleum-based diesel fuel blendstocks or a finished distillate fuel in the distribution system. Likewise, bio-gasoline or bio-butanol could potentially be treated as petroleum-based gasoline blendstocks.[157] This also might open the possibility for additional transport by pipeline. However, the location of plants that produce such biofuels relative to petroleum pipeline origination points would continue to be an issue limiting the usefulness of existing pipelines for biofuel distribution.[158]

1. Overview of Ethanol Distribution

Pipelines are the preferred method of shipping large volumes of petroleum products over long distances because of the relative low cost and reliability. Ethanol is currently not commonly shipped by pipeline because it can cause stress corrosion cracking in pipeline walls and its affinity for water and solvency can result in product contamination concerns.[159] Shipping ethanol in pipelines that carry distillate fuels as well as gasoline also presents unique difficulties in coping with the volumes of a distillate-ethanol mixture which would typically result.[160] It is not possible to re-process this mixture in the way that diesel-gasoline mixtures resulting from pipeline shipment are currently handled.[161] Substantial testing and analysis is currently underway to resolve these concerns so that ethanol may be shipped by pipeline either in a batch mode or blended with petroleum-based fuel.[162] By the time of the publication of this proposal, results of these evaluations may be available regarding what actions are necessary by multi-product pipelines to overcome safety and product contamination concerns associated with shipping 10% ethanol blends. A short gasoline pipeline in Florida has begun shipping

[152] ''Ethanol Transportation Backgrounder, Expansion of U.S. Corn-based Ethanol from the Agricultural Transportation Perspective'', USDA, September 2007, *http://www.ams.usda.gov/tmd/TSB/EthanolTransportationBackgrounder09-17-07.pdf.*

[153] *For example:* (1) The Biomass Research and Development Board, a government study group, has formed a task group on biofuels distribution infrastructure that is composed of experts on biofuel distribution from a broad range of governmental agencies. (2) The National Commission on Energy Policy, an independent advisory group, has formed a task group of fuel distribution experts to make recommendations on the steps needed to facilitate the distribution of biofuels. (3) The Association of Oil Pipelines is conducting research to evaluate what steps are necessary to allow the distribution of ethanol blends by pipeline.

[154] *http://www.ers.usda.gov/FarmBill/2008/Titles/TitleIXEnergy.htm#infrastructure.*

[155] Additional discussion can be found in Section 1.6 of the DRIA.

[156] The costs associated with making the necessary changes to the fuel distribution infrastructure are discussed in Section VIII.B of today's preamble.

[157] Biogasoline might also potentially be treated as finished fuel.

[158] The projected location of biofuel plants would not be affected by the choice of whether they are designed to produce ethanol, distillate fuel, bio-gasoline, or butanol. Proximity to the feedstock would continue to be the predominate consideration. The use of pipelines is being considered for the shipment of bio-oils manufactured from cellulosic feedstocks to refineries where they could be converted into renewable diesel fuel or renewable gasoline. The distribution of biofuel feedstocks is discussed in Section 1.3 of the DRIA.

[159] Stress corrosion cracking could lead to a pipeline leak. The potential impacts on water from today's proposal are discussed in Section X of today's preamble.

[160] Different grades of gasoline and diesel fuel are typically shipped in multi-product pipelines in batches that abut each other. To the extent possible, products are sequenced in a way to allow the interface mixture between batches to be cut into one of the adjoining products. In cases where diesel fuel abuts gasoline in the pipeline, the resulting mixture must typically be reprocessed into its component parts by distillation for resale as gasoline and diesel fuel.

[161] Gasoline-ethanol mixtures can be blended into finished gasoline.

[162] *Association of Oil Pipelines: http://aopl.org/go/searchresults/888/?q=ethanol&sd=&ed=.* ''Hazardous Liquid Pipelines Transporting Ethanol, Ethanol Blends, and Other Biofuels'', Notice of policy statement and request for comment, Pipeline and Hazardous Materials Safety Administration, Department of Transportation, August 10, 2007, 72 FR 45002.

batches of ethanol.[163] Thus, existing petroleum pipelines in some areas of the country might play a role in the shipment of ethanol from the points of production/importation to petroleum terminals.

However, the location of ethanol plants in relation to existing pipeline origination points will limit the role of existing pipelines in the shipment of ethanol.[164] Current corn ethanol production facilities are primarily located in the Midwest far from the origination points of most existing product pipelines and the primary gasoline demand centers. We project that a substantial fraction of future cellulosic ethanol plants will also be located in the Midwest, although a greater proportion of cellulosic plants are expected to be dispersed throughout the country compared to corn ethanol plants. The projected locations for this subset of future cellulosic ethanol plants more closely coincide with the origination points of product pipelines in the Gulf Coast.[165] Imported ethanol could also be brought into ports near the origination point of product pipelines in the Gulf Coast and the Northeast. Nevertheless, the majority of ethanol will continue to be produced at locations distant from the origination points of product pipelines and gasoline demand centers. The gathering of ethanol from production facilities located in the Midwest and shipment by barge down the Mississippi for introduction to pipelines in the Gulf Coast is under consideration. However, the additional handling steps to bring the ethanol to the pipeline origin points in this manner could negate any potential benefit of shipment by existing petroleum pipelines compared to direct shipment by rail.

Evaluations are also currently underway regarding the feasibility of constructing a new dedicated ethanol pipeline from the Midwest to the East Coast.[166] Under such an approach, ethanol would be gathered from a number of Midwest production facilities to provide sufficient volume to justify pipeline operation. To the extent that ethanol production would be further concentrated in the Midwest due to the siting of cellulosic ethanol plants, this would tend to help justify the cost of installing a dedicated ethanol pipeline. Substantial issues would need to be addressed before construction on such a pipeline could proceed, including those associated with securing new rights-of-ways and establishing sufficient surety regarding the return on the several billion dollar investment.

Due to the uncertainties regarding the degree to which pipelines will be able to participate in the transportation of ethanol, we assumed that ethanol will continue to be transported by rail, barge, and truck to the terminal where it will be blended into gasoline. The distribution by these modes can be further optimized primarily through the increased shipment by unit train and installation of additional hub delivery terminals that can accept large volumes of ethanol for further distribution to satellite terminals. To the extent that pipelines do eventually play a role in the distribution of ethanol, this could tend to reduce distribution costs and improve reliability in supply.

USDA estimated that in 2005 approximately 60% of ethanol was transported by rail, 30% was transported by tank truck, and 10% was transported by barge.[167] Denatured ethanol is shipped from production/import facilities to petroleum terminals where it is blended with gasoline. When practicable, shipment by unit train is the preferred method of rail shipment rather than shipping on a manifest rail car basis. The use of unit trains, sometimes referred to as a virtual pipeline, substantially reduces shipping costs and improves reliability. Unit trains are composed entirely of 70–100 ethanol tank cars, and are dedicated to shuttle back and forth to large hub terminals.[168] Manifest rail car shipment refers to the shipment of ethanol in rail tank cars that are incorporated into trains which are composed of a variety of other commodities. Unit trains can be assembled at a single ethanol production plant or if a group of plants is not large enough to support such service individually, can be formed at a central facility which gathers ethanol from a number of producers. The Manly Terminal in Iowa, which is the first such ethanol gathering facility, accepts ethanol from a number of nearby ethanol production facilities for shipment by unit train. Regional (Class 2) railroad companies are an important link bringing ethanol to gathering facilities for assembly into unit trains for long-distance shipment by larger (Class 1) railroads. Ethanol is sometimes carried by multiple modes before finally arriving at the terminal where it is blended into gasoline. For example, some ethanol is currently shipped from the Midwest to a hub terminal on the East Coast by unit train where a portion is further shipped to satellite terminals by barge or tank truck.

Ethanol is blended into gasoline at either 10 or 85 volume percent at terminals (to produce E10 and E85) for delivery to retail and fleet facilities by tank truck. Special retail delivery hardware is needed for E85 which can be used in flexible fuel vehicles only.[169] The large volume of ethanol that we project will be used by 2022 means that more ethanol will need to be used than can be accommodated by blending to the current legal limit of 10% in all of the gasoline used in the country. This will require the installation of a substantial number of new E85 refueling facilities and the addition of a substantial number of flex-fuel vehicles to the fleet. Concerns have been raised regarding the inducements that would be necessary for retailers to install the needed E85 facilities and for consumers to purchase E85.[170] As discussed in Section V.D. of today's preamble, this is prompting many to evaluate whether a mid-level ethanol blend (e.g. E15) might be allowed for use in existing (non-flex-fuel) vehicles. Current refueling equipment (not designed for E85) is only certified for ethanol blends up to 10 volume percent (E10).[171] Hence, if a mid-level ethanol blend were to be introduced, fuel retail facilities would need to ensure that the equipment used to store/dispense mid-level ethanol

[163] Article on shipment of ethanol in Kinder Morgan pipeline: *http://www.ethanolproducer.com/article.jsp?article_id=5149.*

[164] Some small petroleum product refineries are currently limited in their ability to ship products by pipeline because their relatively low volumes were not sufficient to justify connection to the pipeline distribution system.

[165] A discussion of the projected location of cellulosic ethanol plants is contained in Section 1.5 of the DRIA.

[166] Magellan and Poet joint assessment of dedicated ethanol pipeline: *http://www.magellanlp.com/news/2009/20090316_5.htm.*

[167] "Ethanol Transportation Backgrounder, Expansion of U.S. Corn-based Ethanol from the Agricultural Transportation Perspective", USDA, September 2007, *http://www.ams.usda.gov/tmd/TSB/EthanolTransportationBackgrounder09-17-07.pdf.*

[168] Hub ethanol receipt terminals can be located at large petroleum terminals or at rail terminals.

[169] The cost of retail dispensing hardware which is tolerant to ethanol blends greater than E10 is discussed in Section VIII.B. of today's preamble and discussed in more detail in Section 4.2 of the DRIA.

[170] See Section V.D of today's preamble for a discussion of issues related to use of the projected volumes of ethanol that would be produced to comply with the RFS2 standards.

[171] Underwriters Laboratory certifies retail refueling equipment. UL stated that they have data which indicates that the use of fuel dispensers certified for up to E10 blends to dispense blends up to a maximum ethanol content of 15 volume percent would not result in critical safety concerns (*http://www.ul.com/newsroom/newsrel/nr021909.html*). Based on this, UL stated that it would support authorities having jurisdiction who decide to permit legacy equipment originally certified for up to E10 blends to be used to dispense up to 15 volume percent ethanol. The UL announcement did address the compatibility of underground storage tank systems with greater than E10 blends.

blends is compatible with the mid-level ethanol blend.[172] Underwriters Laboratories has one certification standard for fuel retail equipment that covers ethanol blends up to 10%, and a separate certification standard for equipment that dispenses ethanol blends above 10% (including E85).[173]

Should other biofuels be introduced that do not require differentiation from diesel fuel or gasoline in place of some of the volume of ethanol that we project would be used under the RFS2 standards, this may tend to reduce the need for changes at fuel retail facilities and the need for flex-fuel vehicles. Concerns about the difficulties/costs associated with expanding the ethanol distribution infrastructure and adding a sufficient number of vehicles capable of using 10% ethanol to fleet is generating increased industry interest in renewable diesel and gasoline which would be more transparent to the existing fuel distribution system.

2. Overview of Biodiesel Distribution

Biodiesel is currently transported from production plants by truck, manifest rail car, and by barge to petroleum terminals where it is blended with petroleum-based diesel fuel. Unblended biodiesel must be transported and stored in insulated/heated containers in colder climes to prevent gelling. Insulated/heated containers are not needed for biodiesel that has been blended with petroleum-based diesel fuel (i.e., B2, B5). Biodiesel plants are not as dependent on being located close to feedstock sources as are corn and cellulosic ethanol plants.[174] Biodiesel feedstocks are typically preprocessed to oil prior to shipment to biodiesel production facilities. This can substantially reduce the volume of feedstocks shipped to biodiesel plants relative to ethanol plants, and has allowed some biodiesel plants to be located adjacent to petroleum terminals. Biodiesel production facilities are more geographically dispersed than ethanol facilities and the production volumes also tend to be smaller than ethanol facilities.[175] These characteristics in combination with the smaller volumes of biodiesel that we project will be used under the RFS2 standards compared to ethanol allow relatively more biodiesel to be used within trucking distance of the production facility. However, we project that there will continue to be a strong and growing demand for biodiesel as a blending component in heating oil which could not be satisfied alone by local sources of production. It is likely that state biodiesel mandates will also need to be satisfied in part by out-of-state production. Fleets are also likely to continue to be a substantial biodiesel user, and these will not always be located close to biodiesel producers. Thus, we are assuming that a substantial fraction of biodiesel will continue to be shipped long distances to market. Downstream of the petroleum terminal, B2 and B5 can be distributed in the same manner as petroleum diesel.

Concerns remain regarding the shipment of biodiesel by pipeline (either by batch mode or in blends with diesel fuel) related to the contamination of other products (particularly jet fuel), the solvency of biodiesel, and compatibility with pipeline gaskets and seals.[176] The smaller anticipated volumes of biodiesel and the more dispersed and smaller production facilities relative to ethanol also make biodiesel a less attractive candidate for shipment by pipeline. Due to the uncertainties regarding the suitability of transporting biodiesel by pipeline, we assumed that biodiesel which needs to be transported over long distance will be carried by manifest rail car and to a lesser extent barge. Due to the relatively small plant size and dispersion of biodiesel plants, we anticipate the volumes of biodiesel that can be gathered at a single location will continue to be insufficient to justify shipment by unit train. To the extent that pipelines do eventually play a role in the distribution of biodiesel, this could tend to reduce distribution costs and improve reliability in supply.

3. Overview of Renewable Diesel Distribution

We believe that renewable diesel fuel will be confirmed to be sufficiently similar to petroleum-based diesel fuel blendstocks with respect to distribution system compatibility. Hence, renewable diesel fuel could be treated in the same manner as any petroleum-based diesel fuel blendstock with respect to transport in the existing petroleum distribution system. Approximately two-thirds of renewable diesel fuel is projected to be produced at petroleum refineries.[177] The transport of such renewable diesel fuel would not differ from petroleum-based diesel fuel since it would be blended to produce a finished diesel fuel before leaving the refinery. The other one-third of renewable diesel fuel is projected to be produced at stand-alone facilities located more closely to sources of feedstocks. We anticipate that such renewable diesel fuel would be shipped by tank truck to nearby petroleum terminals where it would be blended directly into diesel fuel storage tanks. Because of its high cetane and value, we anticipate that all renewable diesel fuel would likely be blended with petroleum based diesel fuel prior to use. Downstream of the terminal, renewable/petroleum diesel fuel mixtures would be distributed the same as petroleum diesel.

4. Changes in Freight Tonnage Movements

To evaluate the magnitude of the challenge to the distribution system up to the point of receipt at the terminal, we compared the growth in freight tonnage for all commodities from the AEO 2007 reference case to the growth in freight tonnage under the RFS2 standards in which ethanol increases, as does the feedstock (corn) and co-products (distillers grains). We did not include a consideration of the distribution of cellulosic ethanol feedstocks on freight tonnage for the proposal. We intend to evaluate this in the final rule. For purposes of this analysis, we focused on only the ethanol portion of the renewable fuel goals for ease of calculation and because ethanol represents the vast majority of the total volume of biofuel. The resulting calculations serve as an indicator of changes in freight tonnages associated with increases in renewable fuels. We calculated the freight tonnage for the total of all modes of transport as well as the individual cases of rail, truck, and barge.

[172] Although it has yet to be established, most underground steel storage tanks themselves would likely be compatible with ethanol blends greater than 10 percent. The compatibility of piping, submersed pumps, gaskets, and seals associated with these tanks with ethanol blends greater than 10% would also need to be evaluated. Some fiberglass tanks are incompatible and would need to be replaced. It is difficult and sometimes impossible to verify the suitability of underground storage tanks and tank-related equipment for E85 use. The State of California prohibits the conversion of underground storage tanks to E85 use. Significant changes to dispensers, including hoses, nozzles, and other miscellaneous fittings would be needed to ensure they are compatible with ethanol blends greater than 10 percent.

[173] Joint UL/DOE Legacy System Certification Clarification *http://www.ul.com/global/eng/documents/offerings/industries/chemicals/flammableandcombustiblefluids/development/UL_DOE_LegacySystemCertification.pdf.*

[174] Biodiesel feedstocks are typically preprocessed to oil prior to shipment to biodiesel production facilities. This can substantially reduce the volume of feedstocks shipped to biodiesel plants relative to ethanol plants.

[175] Section 1.2 contains a discussion of our projections regarding the location of biodiesel production facilities.

[176] Industry evaluations are currently underway to resolve these concerns.

[177] Either co-processed with crude oil or processed in separate units at the refinery for blending with other refinery diesel blendstocks.

In calculating the reference case percent growth rate in total freight tonnage, we used data compiled by the Federal Highway Administration to calculate the tonnages associated with these commodities.[178] We then calculated the growth in freight tonnage for 2022 under the RFS2 standards and compared the difference with the reference case. The comparisons indicate that across all transport modes, the incremental increase in freight tonnage of ethanol and accompanying feedstocks and co-products associated with the increased ethanol volume under the RFS2 standards are small. The percent increase for total freight across all modes (including pipeline) by 2022 is 0.9 percent. Because pipelines currently do not carry ethanol, and the increase in the volume of ethanol used in motor vehicles displaces a corresponding volume of gasoline, pipelines showed a decrease in the total tonnage carried due to a decrease in the volume of gasoline carried by pipeline. The displaced gasoline also resulted in some decrease in tonnage in other modes that slightly reduced the overall increases in tonnage reflected in the totals.

To further evaluate the magnitude of the increase in freight tonnage under the RFS2 standards, we calculated the portion of the total freight tonnage for rail, barge, and truck modes made up of ethanol-related freight for both the 2022 and control cases. The freight associated with ethanol constitutes only a very small portion of the total freight tonnage for all commodities. Specifically, ethanol freight represents approximately 0.5% and 2.5% of total freight for the reference case and RFS2 standards case, respectively. The results of this analysis suggest that it should be feasible for the distribution infrastructure upstream of the terminal to accommodate the additional freight associated with this RFS2 standards especially given the lead time available. Specific issues related to transportation by rail, barge, and tank truck are discussed in the following sections. We intend to incorporate the results of a recently completed study by Oak Ridge National Laboratory (ORNL) on the potential constraints in ethanol distribution into the analysis for the final rule.[179] The ORNL study concluded that the increase in ethanol transport would have minimal impacts on the overall transportation system. However, the ORNL study did identify localized areas where significant upgrades to the rail distribution system would likely be needed.

5. Necessary Rail System Accommodations

Many improvements to the freight rail system will be required in the next 15 years to keep pace with the large increase in the overall freight demand. Improvements to the freight railroad infrastructure will be driven largely by competition in the burgeoning inter-model transport sector. As inter-model freight represents the vast majority of all freight hauled by these railroads, the biofuels transport sector can be expected to benefit from the infrastructure build-out resulting from inter-model transport sector competition. As such, most of the needed upgrades to the rail freight system are not specific to the transport of renewable fuels and would be needed irrespective of today's proposed rule. We also expect that the excess rail capacity associated with inter-model build-out to be adequately large to absorb potential increases in truck transport associated with fuel cost increases. The modifications required to satisfy the increase in demand include upgrading tracks to allow the use of heavier trains at faster speeds, the modernization of train braking systems to allow for increased traffic on rail lines, the installation of rail sidings to facilitate train staging and passage through bottlenecks.

Some industry groups [180] and governmental agencies in discussions with EPA, and in testimony provided for the Surface Transportation Board (STB) expressed concerns about the ability of the rail system to keep pace with the large increase in demand even under the reference case (27% by 2022). For example, the electric power industry has had difficulty keeping sufficient stores of coal in inventory at power plants due to rail transport difficulties and has expressed concerns that this situation will be exacerbated if rail congestion worsens. One of the more sensitive bottleneck areas with respect to the movement of ethanol from the Midwest to the East coast is Chicago. The City of Chicago commissioned its own analysis of rail capacity and congestion, which found that the lack of rail capacity is ''no longer limited to a few choke points, hubs, and heavily utilized corridors.'' Instead, the report finds, the lack of rail capacity is ''nationwide, affecting almost all the nation's critically important trade gateways, rail hubs, and intercity freight corridors.''

Significant private and public resources are focused on making the modifications to the rail system to cope with the increase in demand. Rail carriers report that they typically invest $16 to $18 billion a year in infrastructure improvements.[181] Substantial government loans are also available to small rail companies to help make needed improvements by way of the Railroad Rehabilitation and Improvement Finance (RRIF) Program, administered by Federal Railroad Administration (FRA), as well as Section 45G Railroad Track Maintenance Credits, offered by the Internal Revenue Service (IRS). The American Association of State Highway Transportation Officials (AASHTO) estimates that between $175 billion and $195 billion must be invested over a 20-year period to upgrade the rail system to handle the anticipated growth in freight demand, according to the report's base-case scenario.[182] The report suggests that railroads should be able to provide up to $142 billion from revenue and borrowing, but that the remainder would have to come from other sources including, but not limited, to loans, tax credits, sale of assets, and other forms of public-sector participation. Given the reported historical investment in rail infrastructure, it may be reasonable to assume that rail carriers would be able to manage the $7.1 billion in annual investment from rail carriers that AASHTO projects would be needed to keep pace with the projected increase in freight demand.

However, the Government Accounting Office (GAO) found that it is not possible to independently confirm statements made by Class I rail carriers regarding future investment plans.[183] In

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[178] *http://www.ops.fhwa.dot.gov/freight/freight_analysis/faf/index.htm.*

[179] ''Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints'', prepared for EPA by Oak Ridge National Laboratory, March 2009.

[180] Industry groups include the Alliance of Automobile Manufacturers, American Chemistry Council, and the National Industrial Transportation League; governmental agencies include the Federal Railroad Administration (FRA), the Government Accountability Office (GAO), and the American Association of State Highway Transportation Officials (AASHTO). Testimony for the STB public hearings includes Ex Parte No. 671, *Rail Capacity and Infrastructure Requirements and Ex Parte No. 672, Rail Transportation and Resources Critical to the Nation's Energy Supply.*

[181] ''The Importance of Adequate Rail Investment'', Association of American Railroads, *http://www.aar.org/GetFile.asp?File_ID=150.*

[182] AASHTO Freight-Rail Bottom-Line Report, 2003.

[183] The railroads interviewed by GAO were generally unwilling to discuss their future investment plans with the GAO. Therefore, GAO was unable to comment on how Class I freight rail companies are likely to choose among their competing investment priorities for the future, including those of the rail infrastructure, GAO

Continued

addition, questions persist regarding allocation of these investments, with the Alliance of Automobile Manufacturers, American Chemistry Council, National Industrial Transportation League, and others expressing concern that their infrastructural needs may be neglected by the Class I railroads in favor of more lucrative intermodal traffic. Moreover, the GAO has raised questions regarding the competitive nature and extent of Class I freight rail transport. This raises some concern that providing sufficient resources to facilitate the transport of increasing volumes of ethanol and biodiesel might not be a first priority for rail carriers. In response to GAO concerns, the Surface Transportation Board (STB) agreed to undertake a rigorous analysis of competition in the freight railroad industry.[184]

Given the broad importance to the U.S. economy of meeting the anticipated increase in freight rail demand, and the substantial resources that seem likely to be focused on this cause, we believe that overall freight rail capacity would not be a limiting factor to the successful implementation of the biofuel requirements to meet the RFS2 standards. Evidence from the recent ramp up of ethanol use has also shown that rail carriers are enthusiastically pursuing the shipment of ethanol. Class 2 railroads have been particularly active in gathering sufficient numbers of ethanol cars to allow Class 1 railroads to ship ethanol by unit train. Likewise, we believe that that Class 2 railroads and, to a lesser extent, the trucking industry, will play a key role in the transportation of DDGs and other byproducts from regions with concentrated ethanol production facilities to those with significant livestock operations. Based on this recent experience, we believe that ethanol will be able to compete successfully with other commodities in securing its share of freight rail service.

While many changes to the overall freight rail system are expected to occur irrespective of today's proposed rule, a number of ethanol-specific modifications will be needed. For instance, a number of additional rail terminals are likely to be configured for receipt of unit trains of ethanol for further distribution by tank truck or other means to petroleum terminals. The placement of ethanol unit train receipt facilities at rail terminals would be particularly useful in situations where petroleum terminals might find it difficult or impossible to install their own ethanol rail receipt capability. We anticipate that ethanol storage will typically be installed at rail terminal ethanol receipt hubs over the long run. We do not anticipate that the rail industry will experience substantial difficulty in installing such ethanol-specific facilities once a clear long term demand for ethanol in the target markets has been established to justify the investment. However, the need for long-term demand to be established prior to the construction of such facilities will likely mean that the needed facilities will, at best, come on-line on a just-in-time basis. This may lead to use of less efficient means of ethanol transport in the short term. The ability to rely on transloading while ethanol storage facilities at rail terminal ethanol receipt hub facilities are constructed will speed the optimization of the distribution of ethanol by rail by allowing the construction of ethanol storage at rail terminal hubs to be delayed.

We estimate that a total of 44,000 rail cars would be needed to distribute the volumes of ethanol and biodiesel that we project would be used in 2022 to satisfy the RFS2 requirements.[185] Our analysis of ethanol and biodiesel rail car production capacity indicates that access to these cars should not represent a serious impediment to meeting the requirements under the RFS2 standards. Ethanol tank car production has increased approximately 30% per year since 2003, with over 21,000 tank cars expected to be produced in 2007. The volume of these newly-produced tank cars, coupled with that of an existing tank car fleet already dedicated to ethanol and biodiesel transport, suggests that an adequate number of these tank cars will be in place to transport the proposed renewable fuel volume requirements in the time available.

We request comment on the extent to which the rail system will be able to deliver the additional volumes of ethanol and biodiesel that we anticipate would be used in response to the RFS2 standards in a timely and reliable fashion. A recently completed report by ORNL identifies specific segments of the rail system which would likely see the most significant increase in traffic due to increased shipments of ethanol under the EISA.[186]

6. Necessary Marine System Accommodations

The American Waterway's Association has expressed concerns about the need to upgrade the inland waterway system in order to keep pace with the anticipated increase in overall freight demand. The majority of these concerns have been focused on the need to upgrade the river lock system on the Mississippi River to accommodate longer barge tows and on dredging inland waterways to allow for movement of fully loaded vessels. We do not anticipate that a substantial fraction of renewable/alternative fuels will be transported via these arteries. Thus, we do not believe that the ability to ship ethanol/biodiesel by inland marine will represent a serious barrier to the implementation of implementation of the requirements under RFS2 standards. Substantial quantities of the corn ethanol co-product dried distiller grains (DDG) is expected to be exported from the Midwest via the Mississippi River as the U.S. demand for DDG becomes saturated. We anticipate that the volume of exported DDG would take the place of corn that would be shifted from export to domestic use in the production of ethanol. Thus, we do not expect the increase in DDG exports to result in a substantial increase in river freight traffic. We request comment on the extent to which marine transport may be used in the transport of cellulosic ethanol feedstocks.

7. Necessary Accommodations to the Road Transportation System

Concerns have been raised regarding the ability of the trucking industry to attract a sufficient number of drivers to handle the anticipated increase in truck freight.[187] The American Trucking Association projected the need for additional 54,000 drivers each year. We estimate that the growth in the use of biofuels through 2022 due to the RFS2 standards would result in the need for a total of approximately 3,000

testimony Before the Subcommittee on Surface Transportation and Merchant Marine, Senate Committee on Commerce, Science, and Transportation, U.S. Senate, *Freight Railroads Preliminary Observations on Rates, Competition, and Capacity Issues,* Statement of JayEtta Z. Hecker, Director, Physical Infrastructure Issues, GAO, GAO–06–898T (Washington, DC: June, 21, 2006).

[184] GAO, *Freight Railroads: Industry Health Has Improved, but Concerns about Competition and Capacity Should Be Addressed,* GAO–07–94 (Washington, DC: Oct. 6, 2006); GAO, *Freight Railroads: Updated Information on Rates and Other Industry Trends,* GAO–07–291R Freight Railroads (Washington, DC: Aug. 15, 2007). STB's final report, entitled *Report to the U.S. STB on Competition and Related Issues in the U.S. Freight Railroad Industry,* is expected to be completed November, 1, 2008.

[185] A discussion of how we arrived at the estimated number of tank cars needed is contained in Section 4.2 of the DRIA.

[186] ''Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints'', prepared for EPA by Oak Ridge National Laboratory, March 2009.

[187] ''The U.S. Truck Driver Shortage: Analysis and Forecasts'', Prepared by Global Insights for the American Trucking Association, May 2005. *http://www.truckline.com/NR/rdonlyres/E2E789CF–F308–463F–8831–0F7E283A0218/0/ATADriverShortageStudy05.pdf.*

additional trucks drivers. Given the relatively small number of new truck drivers needed to transport the volumes of biofuels needed to comply with the RFS2 standards through 2022 compared to the total expected increase in demand for drivers over the same time period (>750,000), we do not expect that the implementation of the RFS2 standards would substantially impact the potential for a shortage of truck drivers. However, specially certified drivers are required to transport ethanol and biodiesel because these fuels are classified as hazardous liquids. Thus, there may be a heightened level of concern about the ability to secure a sufficient number of such specially certified tank truck drivers to transport ethanol and biodiesel. The trucking industry is involved in efforts to streamline the certification of drivers for hazardous liquids transport and more generally to attract and retrain a sufficient number of new truck drivers.

Truck transport of biofuel feedstocks to production plants and finished biofuels and co-products from these plants is naturally concentrated on routes to and from these production plants. This may raise concerns about the potential impact on road congestion and road maintenance in areas in the proximity of these facilities. We do not expect that such potential concerns would represent a barrier to the implementation of the RFS2 standards. The potential impact on local road infrastructure and the ability of the road network to be upgraded to handle the increased traffic load is an inherent part in the placement of new biofuel production facilities. Consequently, we expect that any issues or concerns would be dealt with at the local level.

We request comment on the extent to which satisfying the requirements under the RFS2 standards might exacerbate the anticipated shortage of truck drivers or lead to localized road congestion and condition problems. Comment is further requested on the means to mitigate such potential difficulties to the extent they might exist.

8. Necessary Terminal Accommodations

Terminals will need to install additional storage capacity to accommodate the volume of ethanol/biodiesel that we anticipate will be used in response to the RFS2 standards. Questions have been raised about the ability of some terminals to install the needed storage capacity due to space constraints and difficulties in securing permits.[188] Overall demand for fuel used in spark ignition motor vehicles is expected to remain relatively constant through 2022. Thus, much of the demand for new ethanol and biodiesel storage could be accommodated by modifying storage tanks previously used for the gasoline and petroleum-based diesel fuels that would displaced by ethanol and biodiesel. The areas served by existing terminals also often overlap. In such cases, one terminal might be space constrained while another serving the same area may be able to install the additional capacity to meet the increase in demand. Terminals with limited ethanol storage (or no access to rail/barge ethanol shipments) could receive truck shipments of ethanol from terminals with more substantial ethanol storage (and rail/barge receipt) capacity. The trend towards locating ethanol receipt and storage capability at rail terminals located near petroleum terminals is likely to be an important factor in reducing the need for large volume ethanol receipt and storage facilities at petroleum terminals. In cases where it is impossible for existing terminals to expand their storage capacity due to a lack of adjacent available land or difficulties in securing the necessary permits, new satellite storage or new separate terminal facilities may be needed for additional ethanol and biodiesel storage. However, we believe that there would be few such situations.

Another question is whether the storage tank construction industry would be able to keep pace with the increased demand for new tanks that would result from today's proposal. The storage tank construction industry recently experienced a sharp increase in demand after years of relatively slack demand for new tankage. Much of this increase in demand was due to the unprecedented increase in the use of ethanol. Storage tank construction companies have been increasing their capabilities which had been pared back during lean times.[189] Given the projected gradual increase in the need for biofuel storage tanks, it seems reasonable to conclude that the storage tank construction industry would be able to keep pace with the projected demand.

The RFG and anti-dumping regulations currently require certified gasoline to be blended with denatured ethanol to produce E85. The gasoline must meet all applicable RFG and anti-dumping standards for the time and place where it is sold. We understand that some parties may be blending butanes and or pentanes into gasoline before it is blended with denatured ethanol in order to meet ASTM minimum volatility specifications for E85 that were set to ensure proper drivability, particularly in the winter.[190] If terminal operators add blendstocks to finished gasoline for use in manufacturing E85, the terminal operator would need to register as a refiner with EPA and meet all applicable standards for refiners.

Recent testing has shown that much of in-use E85 does not meet minimum ASTM volatility specifications.[191] However, it is unclear if noncompliance with these specifications has resulted in a commensurate adverse impact on drivability. This has prompted a re-evaluation of the fuel volatility requirements for in-use E85 vehicles and whether the ASTM E85 volatility specifications might be relaxed.[192] For the purpose of our analysis, we are assuming that certified gasoline currently on hand at terminals can be used to make up the non-ethanol portion of E85.[193]

We request comment on the extent that this will be the case in light of the projected outcome of the ASTM process. Comment is requested on the fraction of terminals that currently have butane/pentane blending capability and the logistical/cost implications of adding such capability including sourcing and transportation issues associated with supplying these blending components to the terminal for the purpose of blending E85 to ASTM specifications. We also seek comment on whether we should include a separate section in the RFS2 regulations to specify the requirements for producing E85, and whether we should provide E85 manufacturers who use blendstocks to produce E85 with any flexibilities in complying with the refiner requirements.[194]

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[188] The Independent Fuel Terminal Operators Association represents terminals in the Northeast.

[189] It currently may take 4 to 8 months to begin construction of a storage tank after a contract is signed due to tightness in construction assets and steel supply.

[190] ''Specification for Fuel Ethanol (Ed75–Ed85) for Spark-Ignition Engines'', American Society for Testing and Materials standard ASTM D5798.

[191] Coordinating Research Council (CRC) report No. E–79–2, Summary of the Study of E85 Fuel in the USA Winter 2006–2007, May 2007. *http://www.crcao.org/reports/recentstudies2007/E–79–2/E–79–2%20E85%20Summary%20Report%202007.pdf.*

[192] CRC Cold Start and Warm-up E85 Driveability Program, *http://www.crcao.com/about/Annual%20Report/2007%20Annual%20Report/Perform/CM–133.htm.*

[193] This is different from the approach taken in the refinery modeling which assumed that special blendstocks would be used to blend E85. A discussion of the refinery modeling can be found in Section 4 of the DRIA.

[194] Certain accommodations for butane blenders into gasoline were provided in a direct final rule

Continued

A significant challenge facing terminals and one that is currently limiting the volume of ethanol that can be used is the ability to receive ethanol by rail. Only a small fraction of petroleum terminals currently have rail receipt capability and a number likely have space constraints or are located too far from the rail system which prevents the installation of such capability. The trend to locate ethanol unit train destinations at rail terminals will help to alleviate these concerns. Petroleum terminals within trucking distance of each other are also likely to cooperate so that only one would need to install rail receipt capability. Given the timeframe during which the projected volumes of ethanol ramp up, we believe that these means can be utilized to ensure that a sufficient number of terminals have access to ethanol shipped by rail although some will need to rely on secondary shipment by truck from large ethanol hub receipt facilities. We request comment on the current rail receipt capability at terminals and the extent to which petroleum terminals can be expected to install such capability. Comment is also requested on the extent to which the installation of ethanol receipt facilities at rail terminals can help to meet the need to bring ethanol by rail to petroleum terminals. Our current analysis estimated that half of the new ethanol rail receipt capability needed to support the use of the projected ethanol volumes under the EISA would be installed at petroleum terminals, and half would be installed at rail terminals. A recently completed study by ORNL estimated that all new ethanol rail receipt capability would be installed at existing rail terminals given the limited ability to install such capability at petroleum terminals.[195] We intend to review our estimates regarding the location of the additional ethanol rail receipt facilities for the final rule in light of the ORNL study.

9. Need for Additional E85 Retail Facilities

We estimate that an additional 24,250 E85 retail facilities would be needed to facilitate the consumption of the additional amount of ethanol that we project would be used by 2022 in response to the requirements under the RFS2 standards.[196] On average, this equates to approximately 1,960 new E85 facilities that would need to be added each year from 2009 through 2022 in order to satisfy this goal. This is a very ambitious timeline given that there are less than 2,000 E85 retail facilities in service today. Nevertheless, we believe the addition of these numbers of new E85 facilities may be possible for the industries that manufacture and install E85 retail equipment. Underwriters Laboratories recently finalized its certification requirements for E85 retail equipment.[197] Equipment manufactures are currently evaluating the changes that will be needed to meet these requirements.[198] However, we anticipate the needed changes will not substantially increase the difficulty in the manufacture of such equipment compared to equipment which is specifically manufactured for dispensing E85 today.

We estimate that the cost of installing E85 refueling equipment will average $122,000 per facility which equates to $3 billion by 2022.[199] These costs include the installation of an underground storage tank, piping, dispensers, leak detection, and other ancillary equipment that is compatible with E85.[200] Our E85 facility cost estimates are based on input from fuel retailers and other parties with familiarity in installing E85 compatible equipment. We understand that a certification has yet to be finalized by Underwriters Laboratories for a complete equipment package necessary to store/dispense E85 at a retail facility.[201] Thus, there is some uncertainty regarding the type of equipment that will be needed for compliance with the E85 equipment certification requirements, and the associated costs. Nevertheless, we believe that the E85 equipment that is eventually certified for use will not be substantially different from that on which our cost estimates are based.[202]

Petroleum retailers expressed concerns about their ability to bear the cost installing the needed E85 refueling equipment. Today's proposal does not contain a requirement for retailers to carry E85. We understand that retailers will only install E85 facilities if it is economically advantageous for them to do so and that they will price their E85 and E10 in a manner to recover these costs. While the $3 billion total cost for E85 refueling facilities is a substantial sum, it equates to just 1.5 cents per gallon of E85 throughput.[203] Therefore, we do not believe that the cost of installing E85 refueling equipment will represent an undue burden to retailers given the very large projected consumer demand for E85.

Petroleum retailers also expressed concern regarding their ability to discount the price of E85 sufficiently to persuade flexible fuel vehicle owners to choose E85 given the lower energy density of ethanol. This issue is discussed in Section V.D.2.e. of today's preamble.

D. Ethanol Consumption

1. Historic/Current Ethanol Consumption

Ethanol and ethanol-gasoline blends have a long history as automotive fuels. However, cheap gasoline/blendstocks kept ethanol from making a significant presence in the transportation sector until the end of the 20th century when environmental regulations and tax incentives helped to stimulate growth.

In 1978, the U.S. passed the Energy Tax Act which provided an excise tax exemption for ethanol blended into gasoline that would later be modified through subsequent regulations.[204] In the 1980s, EPA initiated a phase-out of leaded gasoline which created some interest in ethanol as a gasoline

published on December 15, 2005 entitled, ''Modifications to Standards and Requirements for Reformulated and Conventional Gasoline Including Butane Blenders and Attest Engagements'', 70 FR 74552.

[195] ''Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints'', prepared for EPA by Oak Ridge National Laboratory, March 2009.

[196] *See* Section 1.6 of the DRIA for a discussion of the projected number of E85 refueling facilities that would be needed. There would need to be a total of 28,750 E85 retail facilities, 4,500 of which are projected to have been placed in service absent the RFS2 standards.

[197] *See http://ulstandardsinfonet.ul.com/outscope/0087A.html.*

[198] All dispenser equipment except the hose used to dispense fuel to the vehicle has been evaluated by UL. Once suitable hoses have been evaluated, a complete E85 dispenser system can be certified by UL.

[199] See Section 4.2 of the DRIA for a discussion of E85 facility costs. These costs include the installation of 2 pumps with 4 E85 refueling positions at 40% of new facilities, and 1 pump with 2 refueling positions at 60% of new facilities. A sensitivity case was evaluated where it was assumed that all new E85 facilities would install 3 pumps with 6 refueling positions. The cost per facility under this sensitivity case is $166,000.

[200] 40 CFR 280.32 requires that underground storage tank systems must be made of or lined with materials that are compatible with the substance stored in the system.

[201] Underwriters Laboratories recently finalized their requirements for the certification of E85 compatible equipment. No certifications have been completed to date, because of the time needed to complete the application for certification including necessary testing.

[202] All retail dispenser components except the hose that connects the nozzle to the dispenser have been evaluated by UL. Once such hoses have been evaluated by UL, a certification for the complete fuel dispenser assembly may be finalized by UL.

[203] E85 facility costs were amortized over 15 years at 7% and the costs spread over the projected volume of E85 dispensed.

[204] Gasohol, a fuel containing at least 10% biomass-derived ethanol, received a partial exemption from the federal gasoline excise tax. This exemption was implemented in 1979 and a blender's tax credit and a pure alcohol fuel credit were added to the mix in 1980.

oxygenate. Upon passage of the 1990 CAA amendments, states implemented winter oxygenated fuel (''oxyfuel'') programs to monitor carbon monoxide emissions. EPA also established the reformulated gasoline (RFG) program to help reduce emissions of smog-forming and toxic pollutants. Both the oxyfuel and RFG programs called for oxygenated gasoline. However, petroleum-derived ethers, namely methyl tertiary butyl ether (MTBE), dominated oxygenate use until drinking water contamination concerns prompted a switch to ethanol. Additional support came in 2004 with the passage of the Volumetric Ethanol Excise Tax Credit (VEETC). The VEETC provided domestic ethanol blenders with a $0.51/gal tax credit, replacing the patchwork of existing subsidies.[205] The phase-out of MTBE and the introduction of the VEETC along with state mandates and tax incentives created a growing demand for ethanol that surpassed the traditional oxyfuel and RFG markets. By the end of 2004, not only was ethanol the lead oxygenate, it was found to be blended into a growing number of states' conventional gasoline.[206]

In the years that followed, rising crude oil prices and other favorable market conditions continued to drive ethanol usage. In May 2007, EPA promulgated a Renewable Fuel Standard (''RFS1'') in response to EPAct. The RFS1 program set a floor for renewable fuel use reaching 7.5 billion gallons by 2012, the majority of which was ethanol. The country is currently on track for exceeding the RFS1 requirements and meeting the introductory years of today's proposed RFS2 program. For a summary of the growth in U.S. ethanol usage over the past decade, refer to Table V.D.1.–1.

TABLE V.D.1–1—U.S. ETHANOL CONSUMPTION (INCLUDING IMPORTS)

Year	Total ethanol use[a]	
	Trillion BTU	Bgal
1999	120	1.4
2000	138	1.6
2001	144	1.7
2002	171	2.0
2003	233	2.8
2004	292	3.5
2005	334	4.0
2006	451	5.3
2007	566	6.7
2008	792	9.4

[a] EIA Monthly Energy Review March 2009 (Table 10.2).

Through the years, there have also been several policy initiatives to increase the number of flexible fuel vehicles (FFVs) capable of consuming up to 85 volume percent ethanol blends (E85). The Alternative Motor Vehicle Fuels Act of 1988 provided automakers with Corporate Average Fuel Economy (CAFE) credits for producing alternative-fuel vehicles, including FFVs as well as CNG and propane vehicles. Furthermore, the Energy Policy Act of 1992 required government fleets to begin purchasing alternative-fuel vehicles, and the majority of fleets chose FFVs.[207] As a result of these two policy measures, there are over 7 million FFVs on the road today.[208] These vehicles increase our nation's ethanol consumption potential beyond what is capable with conventional vehicles. However, most FFVs are currently refueling on conventional gasoline (E0 or E10) due to limited E85 availability and the fact that E85 is typically priced 20–30 cents per gallon higher than gasoline on an energy equivalent basis. As such, we are not currently tapping into the full ethanol consumption potential of our FFV fleet. However, we expect refueling patterns to change in the future under the RFS2 program.

2. Increased Ethanol Use under RFS2

To meet the RFS2 standards, ethanol consumption will need to be much higher than both today's levels and those projected to occur absent RFS2. The Energy Information Administration (EIA) projected that under business-as-usual conditions, ethanol usage would grow to just over 13 billion gallons by 2022.[209] This represents significant growth from today's usage, however, this volume of ethanol is capable of being consumed by today's vehicle fleet albeit with some fuel infrastructure improvements.[210] Although EIA projected a small percentage of ethanol to be blended as E85 in 2022, 13 billion gallons of ethanol could also be consumed by displacing about 90% of our country's forecasted gasoline energy demand with E10. The maximum amount of ethanol our country is capable of consuming as E10 compared to the projected RFS2 ethanol volumes is shown below in Figure V.D.2–1.[211]

[204] Gasohol, a fuel containing at least 10% biomass-derived ethanol, received a partial exemption from the federal gasoline excise tax. This exemption was implemented in 1979 and a blender's tax credit and a pure alcohol fuel credit were added to the mix in 1980.

[205] The 2008 Farm Bill, discussed in more detail in Section V.B.2.b, replaces the $0.51/gal ethanol blender credit with a $0.45/gal corn ethanol blender credit and also introduces a $1.01/gal cellulosic biofuel producer credit. Both credits are effective January 1, 2009.

[206] Based on 2004 Federal Highway Association (FHWA) State Gasohol Report less estimated RFG and oxyfuel ethanol usage based on EPA's 2004 RFG Fuel Survey results and knowledge of state oxyfuel programs and fuel oxygenates. For more on historical ethanol usage by state and fuel type, refer to Section 1.7.1.1 of the DRIA.

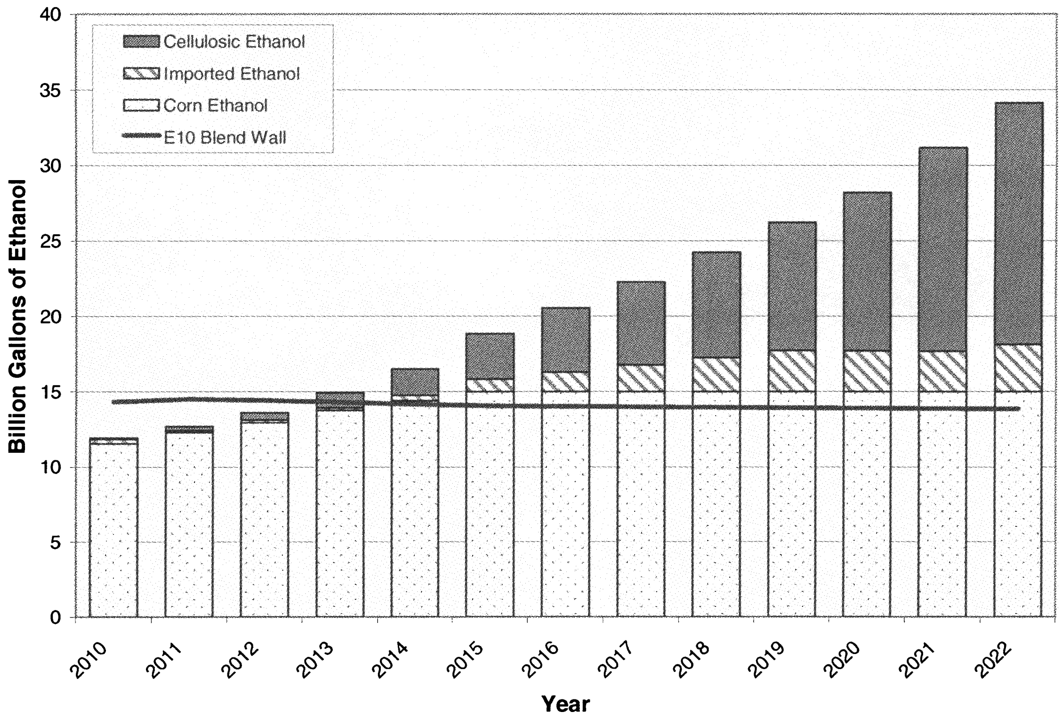
[207] *Source:* June 23, 2008 Federal Times, *Special Report: Fleet Management*.

[208] *Source:* DOE Energy Efficiency and Renewable Energy (worksheet available at *www.eere.energy.gov/afdc/data/index.html*.)

[209] Source: EIA Annual Energy Outlook 2007, Table 17.

[210] For more information on distribution accommodations, refer to Section V.C.

Figure V.D.2-1
Max E10 Ethanol Consumption Compared to RFS2 Requirements[212]



As shown in Figure V.D.2–1, under the proposed RFS2 program, we are projected to hit the E10 ''blend wall'' of about 14.5 billion gallons of ethanol by 2013. This volume corresponds to 100% E10 nationwide. However, if gasoline demand falls, or if E10 cannot get distributed nationwide, the nation could hit the blend wall sooner. Regardless, to get beyond the blend wall and consume more than 14–15 billion gallons of ethanol, we are going to need to see significant increases in the number FFVs on the road, the number of E85 retailers, and the FFV E85 refueling frequency. In the subsections that follow, we will highlight the variables that impact our nation's ethanol consumption potential and, more specifically, what measures the market may need to take in order to consume 34 billion gallons of ethanol by 2022 (assuming the cellulosic biofuel standard and the majority of the advanced biofuel standard are met with ethanol).

As explained in Section V.A.2, our primary RFS2 analysis focuses on ethanol as the main biofuel in the future.[213] In addition, from an ethanol consumption standpoint, we have focused on an E10/E85 world. While E0 is capable of co-existing with E10 and E85 for a while, we assumed that E10 would replace E0 as expeditiously as possible and that all subsequent ethanol growth would come from E85. Furthermore, for our primary analysis, we assumed that no ethanol consumption would come from the mid-level ethanol blends (i.e., E15 or E20) as they are not currently approved for use in non-FFVs. However, in Section V.D.3 below, we discuss the potential approval pathways for mid-level ethanol blends and the volume implications.

We acknowledge that, if approved, mid-level ethanol blends could help the nation meet the proposed RFS2 volume requirements. First, non-FFVs could consume more ethanol per gallon of ''gasoline''. This could result in greater ethanol consumption nationwide. In addition, mid-level blends could allow gasoline retailers to continue to price ethanol relative to gasoline (as it currently is for E10). For these reasons, it is possible that mid-level ethanol blends could help the nation get beyond the E10 blend wall. However, as explained in Section V.D.3.b, there are numerous actions that would need to be taken to bring mid-level ethanol blends to market. In addition, mid-level ethanol blends alone (even if made available nationwide) are not capable of fulfilling the RFS2 requirements in later years. We would essentially hit another blend wall 1–6 years later depending on the intermediate blend, how quickly it could be brought to market, and how widely mid-level ethanol blends were distributed at retail stations nationwide. Nevertheless, this time could be very valuable when it comes to expanding E85/FFV infrastructure and/or commercializing other non-ethanol cellulosic biofuels.

Regardless, our primary analysis focuses on an E10/E85 world because mid-level ethanol blends are not currently approved for use in conventional gasoline vehicles and nonroad equipment. Before usage could be legalized, as discussed more in Section V.D.3 below, EPA would need to grant a waiver declaring that mid-level blends are substantially similar or ''sub-sim'' to gasoline or perhaps even reinterpret the meaning of ''sub-sim''. While such a waiver has not yet been granted, several organizations/agencies are performing vehicle emission testing and investigating other impacts of mid-

[211] The maximum E10 volumes are a function of the gasoline energy demand reported in EIA's Annual Energy Outlook 2009, Table 2 adjusted with lower heating values.

[213] For consideration of other biofuels, refer to Section V.D.3.d.

level blends.[214] Therefore, as a sensitivity analysis, we have analyzed what might need to be done to bring mid-level ethanol blends to market (should a sub-sim waiver be approved) and the extent to which such blends could help our nation meet the RFS2 ethanol standards, at least in the near term. Finally we end our ethanol usage discussion by looking at other strategies for getting beyond the E10 blend wall.

a. Projected Gasoline Energy Demand

The maximum amount of ethanol our country is capable of consuming in any given year is a function of the total gasoline energy demanded by the transportation sector. Our nation's gasoline energy demand is dependent on the number of gasoline-powered vehicles on the road, their average fuel economy, vehicle miles traveled (VMT), and driving patterns. For analysis purposes, we relied on the gasoline energy projections reported by EIA in AEO 2008.[215] Unlike AEO 2007, AEO 2008 takes the fuel economy improvements set by EISA into consideration and also assumes a slight dieselization of the vehicle fleet. The result is a 15% reduction in the projected 2022 gasoline energy demand from AEO 2007 to AEO 2008.[216] EIA basically has gasoline energy demand (petroleum-based gasoline plus ethanol) flattening out, and even slightly decreasing, as we move into the future and implement the EISA vehicle standards.[217]

b. Projected Growth in Flexible Fuel Vehicles

According to DOE's Department of Energy Efficiency and Renewable Energy, there are currently over 7 million FFVs on the road today capable of consuming E85.[218] And that number is growing steadily. Automakers are incorporating more and more FFVs into their light-duty production plans. While the FFV system (i.e., fuel tank, sensor, delivery system, etc.) used to be an option on some vehicles, most FFV producers are moving in the direction of converting entire product lines over to E85-capable systems. Still, the number of FFVs that will be manufactured and purchased in future years is uncertain. For our cost analysis, we examined several different FFV production scenarios. But for our ethanol usage analysis, we focused on one primary FFV scenario, described in more detail below.[219]

In response to President Bush's ''20-in-10'' plan of reducing American gasoline usage by 20% in 10 years, domestic automakers responded with aggressive FFV production goals. General Motors, Ford and Chrysler (referred to hereafter as ''The Detroit 3'') announced plans to produce 50% FFVs by 2012.[220] And despite the current state of the economy and the auto industry, it appears U.S. automakers are still moving forward with their FFV production plans.[221] Assuming that The Detroit 3 continue to maintain 50% market share and that total vehicle sales remain around 16 million per year, at least 4 million FFVs will be produced by the 2012 model year. Based on 2008 offerings, we assumed that approximately 80% of The Detroit 3's FFV production commitment would be met by light-duty trucks and the remaining 20% would be cars.[222] [223] We also assumed that all the FFVs in existence today were produced by The Detroit 3 (and therefore share the same aforementioned car/truck ratio) and that production would ramp up linearly beginning in 2008 to reach the 2012 commitment.

Although non-domestic automakers have not made any official FFV production commitments, Nissan, Mercedes, Izuzu, and Mazda all included at least one flexible fuel vehicle in their 2008 model year offerings.[224] And we anticipate that additional FFVs (or FFV options) will be added in the future. Ultimately, we predict that non-domestic FFV production could be as high as 25%, or about 2 million FFVs per year. While we are not forecasting an official FFV production commitment from the non-domestic automakers, we believe that this represents an aggressive, yet reasonable FFV production estimate for analysis purposes. Furthermore, based on current offerings, we assumed that the majority of non-domestic FFV production would be trucks. With respect to timing, we expect that the non-domestic automakers would ramp up FFV production later than The Detroit 3. For analysis purposes, we assumed that non-domestic automakers would ramp up FFV production beginning in 2013, and like The Detroit 3, it would take about five years for them to reach their FFV production goals (or in this case, the assumed 25% production level)

Based on these FFV assumptions and forecasted vehicle phase-out, VMT, and fuel economy estimates provided by EPA's MOVES Model, we calculate that the maximum percentage of fuel (gasoline/ethanol mix) that could feasibly be consumed by FFVs in 2022 would be about 30%. For more information on our FFV analysis, refer to Section 1.7.1.2.2 of the DRIA.

c. Projected Growth in E85 Access

According to the National Ethanol Vehicle Coalition (NEVC), there are currently over 1,900 retailers offering E85 in 45 states plus the District of Columbia.[225] While this represents significant industry growth, it still only translates to about 1% of U.S. retail stations nationwide carrying the fuel.[226] As a result, most FFV owners clearly do not have reasonable access to E85. For our FFV/E85 analysis, we have defined ''reasonable access'' as one-in-four pumps offering E85 in a given area.[227] Accordingly, just over 4% of the nation currently has reasonable access to E85, up from 3% in 2007 (based on a mid-year NEVC E85 pump estimate).[228]

There are a number of states promoting E85 usage by offering FFV/E85 awareness programs and/or retail pump incentives. A growing number of states are also offering infrastructure grants to help expand E85 availability. Currently, nine Midwest states have adopted a progressive Energy Security and Climate Stewardship Platform.[229]

[214] For more information on mid-level ethanol blends testing, refer to Section V.D.3.b.

[215] For blend wall discussions, we rely on the most recent AEO 2009 projections. However for our detailed ethanol consumption analysis presented in this section (and in more detail in Section 1.7.1 of the DRIA), we relied on AEO 2008.

[216] EIA Annual Energy Outlook 2007 & 2008, Table 2.

[217] For more information on gasoline energy projections, refer to Section 1.7.1.2.1 of the DRIA.

[218] DOE Energy Efficiency and Renewable Energy August 2008 estimate (worksheet available at *www.eere.energy.gov/afdc/data/index.html*).

[219] For more on the FFV production scenarios we considered, refer to Section 1.7.1.2.2 of the DRIA.

[220] Ethanol Producer Magazine, ''View From the Hill.'' July 2007.

[221] Ethanol Producer Magazine, ''Automakers Maintain FFV Targets in Bailout Plans.'' February 2009.

[222] NEVC 2008 Purchasing Guide for Flexible Fuel Vehicles.

[223] Several of the FFV assumptions may need to be revised for the FRM in light of recent events.

[224] *Ibid.*

[225] NEVC FYI Newsletter: Volume 15, Issue 5: March 9, 2009.

[226] Based on National Petroleum News gasoline station estimate of 161,768 in 2008.

[227] For a more detailed discussion on how we derived our one-in-four reasonable access assumption, refer to Section 1.6 of the DRIA. For the distribution cost implications as well as the cost impacts of assuming reasonable access is greater than one-in-four pumps, refer to Section 4.2 of the DRIA.

[228] Computed as percent of stations with E85 (1,963/161,768 as of March 2009 or 1,251/164,292 as of July 2007) divided by 25% (one-in-four stations).

[229] The following states have adopted the plan: Indiana, Kansas, Michigan, Minnesota, Ohio, South Dakota, Wisconsin, Iowa, and most recently, North Dakota. For more information, visit: *http://*

Continued

The platform includes a Regional Biofuels Promotion Plan with a goal of making E85 available at one third of all stations by 2025. In addition, on July 31, 2008, Congresswoman Stephanie Herseth Sandlin (D–SD) and John Shimkus (R–IL) introduced The E85 and Biodiesel Access Act that would amend IRS tax code and increase the existing federal income tax credit from $30,000 or 30% of the total cost of improvements to $100,000 or 50% of the total cost of needed alternative fuel equipment and dispensing improvements.[230] While not signed into law, such a tax credit could provide a significant retail incentive to expand E85 infrastructure.

Given the growing number of state infrastructure incentives and the proposed Federal alternative fuel infrastructure subsidy, it is clear that E85 infrastructure will continue to expand in the future. However, the extent to which nationwide E85 access will grow is difficult to predict, let alone quantify. For analysis purposes, as a practical upper bound, we have selected 70% by 2022. This is roughly equivalent to all urban areas in the United States offering reasonable (one-in-four-station) access to E85.[231] We are not concluding that the percentage of the nation with reasonable access to E85 could not exceed 70% (as a sensitivity, we also modeled the cost impacts of nationwide access to E85) or that availability would necessarily be concentrated in urban areas. However, for analysis purposes, we believe that 70% is a good surrogate for a practical portion of the country that could have reasonable one-in-four access to E85 by 2022 under the proposed RFS2 program. On average, this translates to about 18% of retail stations nationwide offering E85. As discussed in Section V.C, we believe this is feasible based on our assessment of the distribution infrastructure capabilities. For more information on the projected growth in E85 access, refer to Section 1.7.1.2.3 of the DRIA.

d. Required Increase in E85 Refueling Rates

As mentioned above, there were approximately 7 million FFVs on the road in 2008. If all FFVs refueled on E85 100% of the time, this would translate to about 6.5 billion gallons of E85 use.[232] However, E85 usage was only around 12 million gallons in 2008.[233] This means that, on average, FFV owners were only tapping into about 0.2% of their vehicles' E85/ethanol usage potential last year. Assuming that only 4% of the nation had reasonable one-in-four access to E85 in 2008 (as discussed above), this equates to an estimated 5% E85 refueling frequency for those FFVs that had reasonable access to the fuel.

There are several reasons for today's low E85 refueling frequency. For starters, many FFV owners may not know they are driving a vehicle that is capable of handling E85. As mentioned earlier, more and more automakers are starting to produce FFVs by engine/product line, e.g., all 2008 Chevy Impalas are FFVs.[234] Consequently, consumers (especially brand loyal consumers) may inadvertently buy a flexible fuel vehicle without making a conscious decision to do so. And without effective consumer awareness programs in place, these FFV owners may never think to refuel on E85. In addition, FFV owners with reasonable access to E85 and knowledge of their vehicle's E85 capabilities may still not choose to refuel on E85. They may feel inconvenienced by the increased E85 refueling requirements. Based on its lower energy density, FFV owners will need to stop to refuel 21% more often when filling up on E85 over E10 (and likewise, 24% more often when refueling on E85 over conventional gasoline).[235] In addition, some FFV owners may be deterred from refueling on E85 out of fear of reduced vehicle performance or just plain unfamiliarity with the new motor vehicle fuel. However, as we move into the future, we believe the biggest determinant will be price—whether E85 is priced competitively with gasoline based on its reduced energy density and the fact that you need to stop more often, drive a little further to find an E85 station, and depending on the retail configuration, wait in longer lines to fill up on E85.

To comply with the proposed RFS2 program and consume 34 billion gallons of ethanol by 2022, not only would we need more FFVs and more E85 retailers, we would need to see a significant increase in the current FFV E85 refueling frequency. Based on the FFV and retail assumptions described above in subsections (b) and (c), our analysis suggests that FFV owners with reasonable access to E85 in 2022 would need to fill up on it 74% of the time, a significant increase from today's estimated 5% refueling frequency. Were there to be fewer FFVs in the fleet, the E85 refueling frequency would need to be even higher. Similarly, with more FFVs in the fleet, the E85 refueling frequency could be lower and still meet the proposed RFS2 requirements. However, even with an FFV mandate, our analysis suggests that we would need to see an increase from today's average FFV E85 refueling frequency. In order for this to be possible, there will need to be an improvement in the current E85/gasoline price relationship.

e. Market Pricing of E85 Versus Gasoline

According to a recent online fuel price survey, E85 is currently priced almost 30 cents per gallon higher than conventional gasoline on an energy-equivalent basis.[236] To increase our nation's E85 refueling frequency to the levels described above, E85 needs to be priced competitively with (if not lower than) conventional gasoline based on its reduced energy content, increased time spent at the pump, and limited availability. Our analysis, described in more detail in Section 1.7.1.2.5 of the DRIA, suggests that E85 would need to be priced about one-third lower than gasoline at retail (based on 2006 prices) in order for it to be cost-competitive. As expected, higher crude prices could make E85 look slightly more attractive while lower crude oil prices could make E85 look less attractive.

In Brazil, charts are posted at gas stations informing flex-fuel vehicle owners whether it makes sense to fill up on ''gasoline'' (containing 20–25% denatured anhydrous ethanol)[237] or ''alcohol'' (100% denatured hydrous ethanol) based on the price and relative energy density of each. However, in the U.S., FFV owners will likely be on their

www.midwesterngovernors.org/resolutions/Platform.pdf.

[230] A copy of House Rule 6734 can be accessed at: *http://www.e85fuel.com/news/2008/080108_shimkus_release/shimkus.pdf.*

[231] For this analysis, we've defined ''urban'' as the top 150 metropolitan statistical areas according to the U.S. census and/or counties with the highest VMT projections according the EPA MOVES model, all RFG areas, winter oxy-fuel areas, low-RVP areas, and other relatively populated cities in the Midwest.

[232] Based on the assumption that FFV owners travel approximately 12,000 miles per year and get about 18 miles per gallon on average under actual in-use driving conditions. For more information, refer to Section 1.7.1.2.4 of the DRIA.

[233] EIA Annual Energy Outlook 2009, Table 17.

[234] NEVC, ''2008 Purchasing Guide for Flexible Fuel Vehicles.'' Refers to all mass produced 3.5 and 3.9L Impalas. However, it is our understanding that consumers may still place special orders for non-FFVs.

[235] Based on our assumption that denatured ethanol has an average lower heating value of 77,930 BTU/gal and conventional gasoline (E0) has average lower heating value of 115,000 BTU/gal. For analysis purposes, E10 was assumed to contain 10 vol% ethanol and 90 vol% gasoline. Based on EIA's AEO 2008 report, E85 was assumed to contain 74 vol% ethanol and 26 vol% gasoline on average.

[236] Based on average E85 and regular unleaded gasoline prices reported at *http://www.fuelgaugereport.com/* on April 23, 2009.

[237] The government-mandated gasoline ethanol content was 25% as of July 2007. *Source:* F.O. Licht World Ethanol & Biofuels Report Vol. 5 No. 21 July 9, 2007.

own for figuring out which fuel is more economical.

Although in some areas of the country E85 is already priced significantly lower than gasoline, this is a far cry from a nationwide trend. And as we move into the future and incorporate cellulosic ethanol (a fuel that is currently more expensive to produce than corn ethanol), it may be even more difficult to produce ethanol for a price that the market would accept. However, a number of measures could be taken to help encourage FFV E85 refueling.

The first is increased consumer awareness. To maximize ethanol usage, it is important that FFV owners are aware of their vehicle's fueling capabilities, i.e., that their vehicle is capable of refueling on E85. It is equally important that FFV owners are aware of E85 refueling outlets that may be available to them. Automakers and/or car dealerships could notify FFV owners of E85 stations in their area. Together, increased automaker and retail awareness could help increase our nation's E85 throughput potential. However, in order for consumers to actually choose E85 over conventional gasoline on a regular basis, there needs to be a marked price incentive at the pump.

Current federal and most state tax code does not differentiate between ethanol sold as E10 and as E85. As of July 2008, state excise taxes were reported to account for more than $0.18 per gallon of gasoline (on average).[238] However, there are a number of states (e.g., Illinois, Indiana, North Dakota, and South Dakota) that currently waive or discount excise taxes on E85. This type of fuel tax structure helps contribute to a retail price relationship that favors E85 over conventional gasoline.[239] If states continue to waive/reduce E85 fuel taxes under RFS2, this could help increase the FFV E85 refueling frequency. As expected, this would have the greatest impact on ethanol consumption in the areas of the country with the most FFVs.

The E10/E85 price relationship could also be modified by the refining industry. Under the proposed program, gasoline refiners (as well as importers) would be required to purchase RINs to demonstrate that sufficient volumes of renewable/alternative fuels were used to meet their volume obligations. This could provide an incentive for these parties to take the steps necessary to ensure adequate ethanol use levels to facilitate compliance. One potential action that refiners might take to ensure a sufficient RIN supply would be to subsidize the price of the ethanol used to manufacture E85. Such a subsidy might be financed by an increase in their selling price of gasoline. In addition, refiners with marketing arms could adjust the retail price relationship of E10 in E85 in way that encourages E85 throughput while still maintaining the same average net profit. However, a relatively small proportion of refiners market their own gasoline and thus have the ability to make retail price adjustments. Consequently, relying solely on market mechanisms may create some competitive concerns. We request comment on viable and cooperative ways refiners and gasoline retailers could promote E85 throughput to meet the proposed RFS2 requirements.

3. Other Mechanisms for Getting Beyond the E10 Blend Wall

a. Mandate for FFV Production

One way to increase ethanol usage under RFS2 would be if there were more FFVs in the fleet. As described above, our primary analysis is based on the assumption that The Detroit 3 would follow through with their commitment to produce 50% FFVs by 2012 and the non-domestic automakers would ramp up FFV production beginning in 2013 and produce 25% FFVs by 2017. Based on the projected number of FFVs in the fleet (and our E85 infrastructure growth assumptions), FFV owners with reasonable one-in-four access to E85 would need to refuel on it 74% of the time. To achieve this optimistic refueling frequency, we believe there would need to be significant improvements to the E10/E85 price relationship.

One way to reduce the required FFV E85 refueling frequency (and in turn decrease some of the pressure off E85 prices) would be to further increase the number of FFVs in the fleet. While EPA does not have the authority to require automakers to produce FFVs, there are a number of bills in Congress that are set out to do just that. On July 22, 2008 Senator Sam Brownback (R–KS) on behalf of himself and Senators Susan Collins (R–ME), Joseph Lieberman (I–CT), Ken Salazar (D–CO), and John Thune (R–SD) introduced the Open Fuel Standard Act of 2008, a bill that calls for 50% of the U.S. vehicle fleet to be FFVs capable of using high blends of ethanol or methanol (in addition to gasoline) by 2012. This number would grow to 80% by 2015.[240] A similar FFV bill was introduced by Eliot Engel (D–NY) in the House on July 22, 2008.[241]

Since a future congressional mandate on FFV production in being discussed, we have modeled the impact that such a mandate could have on the RFS2 program. For our sensitivity analysis, we found that if automakers were required to make all light-duty vehicles E85-capable by 2015 (and our same E85 infrastructure growth assumptions applied), FFV owners with reasonable one-in-four access to E85 would only need to refuel on it 33% of the time. This represents a smaller increase from today's estimated 5% refueling rate. However, implementing such a FFV mandate would have significant cost implications on the auto industry and would still not provide certainty that FFV owners would fuel on E85. For more information on this analysis, as well as other FFV production scenarios we considered, refer to Section 1.7.1.2.2 of the DRIA.

b. Waiver of Mid-Level Ethanol Blends (E15/E20)

For our primary ethanol usage analysis, we considered that there would only be two fuels in the future, E10 and E85. And as explained in Section V.D.2, we believe it is feasible to consume 34 billion gallons of ethanol by 2022 given growth in FFV production and E85 availability and projected improvements in the current E10/E85 price relationship.

However, several organizations and government entities are interested in increasing the concentration of ethanol beyond the current 10% limit in the commercial gasoline pool. Section 211(f)(1) of the Clean Air Act prohibits the introduction into commerce, or increase in the concentration in use of, gasoline or gasoline additives for use in motor vehicles unless they are substantially similar to the gasoline or gasoline additives used in the certification of new motor vehicles or motor vehicle engines. EPA may grant a waiver of this prohibition under Section 211(f)(4) provided that the fuel or fuel additive ''will not cause or contribute to a failure of any emission control device or system (over the useful life of the motor vehicle, motor vehicle engine, nonroad engine or nonroad vehicle in which the device or system is used) to achieve compliance by the vehicle or engine with the emission standards to

[238] Source: The American Petroleum Institute July 2008 Gasoline Tax Report available at: *http://www.api.org/statistics/fueltaxes/upload/July_2008_gasoline_and_diesel_summary_pages.pdf.*

[239] Source: DOE Energy Efficiency and Renewable Energy Web site (*http://www.eere.energy.gov/*).

[240] Refer to Senate Bill 3303 which can be found at: *http://thomas.loc.gov/cgi-bin/query/z?c110:S.3303.*

[241] Refer to House Rule 6559 which can be found at: *http://thomas.loc.gov/cgi-bin/bdquery/z?d110:H.R.6559.*

which it has been certified.'' The most recent ''substantially similar'' interpretive rule for unleaded gasoline presently allows oxygen content up to 2.7% by weight for certain ethers and alcohols.[242] E10 contains approximately 3.5% oxygen by weight, which makes a gasoline-ethanol blend with ten% ethanol not ''substantially similar'' to certification fuel under the current interpretation.[243] Since any mid-level blend would have a greater than allowed oxygen content, any mid-level blend would need to have a waiver under Section 211(f)(4) of the CAA in order to be sold commercially.

Before EPA grants a 211(f)(4) waiver for a new fuel or fuel additive, an applicant must prove that the new fuel or fuel additive will meet the waiver requirements outlined in the statute. EPA has required that applicants provide vehicle/engine testing for tailpipe emissions, evaporative emissions, materials compatibility, and driveability. Testing needs to include emissions over the full useful life of vehicle and equipment. Several interested parties are investigating the impact that mid-level ethanol blends (e.g., E15 or E20) may have on these areas among others (i.e. catalyst, engine, and fuel system durability, and onboard diagnostics). In order to use the information collected for waiver application purposes, the mid-level ethanol blend testing will need to consider the different engines and fuel systems currently in service that could be exposed to mid-level ethanol blends and the long-term impact of using such blends.[244] After receiving a waiver application, EPA must give public notice and comment and has 270 days to grant or deny the waiver request.

The Department of Energy (DOE) has developed and initiated a comprehensive testing program to investigate the potential impacts of mid-level blends of ethanol. Initial testing was conducted on a limited number of high-volume vehicles and small non-road engines and a preliminary report was published in October, 2008.[245] In addition, DOE is in the process of leveraging existing EPA vehicle and small engine test programs (originally designed to test up to 10% ethanol) to add mid-level ethanol blends to the fuel matrix. DOE's comprehensive test program is intended to evaluate a wide range of emission, performance, and durability issues associated with mid-level ethanol blends (additional reports forthcoming).

DOE is not alone in pursuing mid-level blends. In 2005, the State of Minnesota, a large producer of corn ethanol, passed a law requiring that by 2015, 20% of gasoline (by volume) must be replaced by ethanol. While this level could be achieved with a high percentage of E85 usage by FFVs, the state has also expressed an interest in moving to 20% ethanol blends. Several other states and organizations have also expressed interest in increasing ethanol use by adopting E15 or E20. The Renewable Fuels Association (RFA) and the American Coalition for Ethanol (ACE) have been working with various government entities to investigate the impact of mid-level blends

On March 6, 2009, Growth Energy and 54 ethanol manufacturers submitted an application for a waiver of the prohibition of the introduction into commerce of certain fuels and fuel additives set forth in section 211(f) of the Act. This application seeks a waiver for ethanol-gasoline blends of up to 15 percent by volume ethanol. The statute directs the Administrator of EPA to grant or deny this application within 270 days of receipt by EPA, in this instance December 1, 2009. EPA recently issued a federal register notice announcing receipt of the Growth Energy waiver application and soliciting comment on all aspects of it. Refer to 74 FR 18228 (April 21, 2009).

While the current Growth Energy waiver application is still under review, as a sensitivity, we considered the implications that adding E15 or E20 to the marketplace could have on ethanol usage and the supporting fuel infrastructure should such blends be permitted. For each case, we assumed that E10 would need to continue to remain in existence to meet the demand of legacy vehicle and non-road engine owners. This would also provide consumer choice. Experience in past fuel programs has shown that many consumers will not be comfortable refueling on higher ethanol blends and will blame any problems that may occur on the new fuel (regardless of the actual cause of the vehicle problems) causing a backlash against the new fuel requirements. Therefore, we believe it is critical to continue to allow consumers the choice between mid-level ethanol blends and conventional gasoline (assumed to be E10 in the future).

For our optimistic mid-level ethanol blends scenario, we assumed that E15 or E20 could be available at all retail stations nationwide by the time the nation hits the E10 blend wall, or around 2013. This assumes a number of actions are taken to bring mid-level blends to market (explained in more detail below).[246] We assumed that E10 would be marketed as premium-grade gasoline, the mid-level ethanol blend (E15 or E20) would serve as regular, and like today, midgrade would be blended from the two fuels. Those vehicles and equipment which are unable to refuel on mid-level ethanol blends (or choose not to) could continue to fill up on E10. This mid-level ethanol blends scenario, described in more detail in Section 1.7.1.3 of the DRIA, concluded that if mid-level ethanol blends were to be distributed at all retail stations nationwide, they could help increase ethanol usage to over 19 billion gallons (with E15) and 25 billion gallons (with E20).

[242] 73 FR 22277 (April 25, 2008).

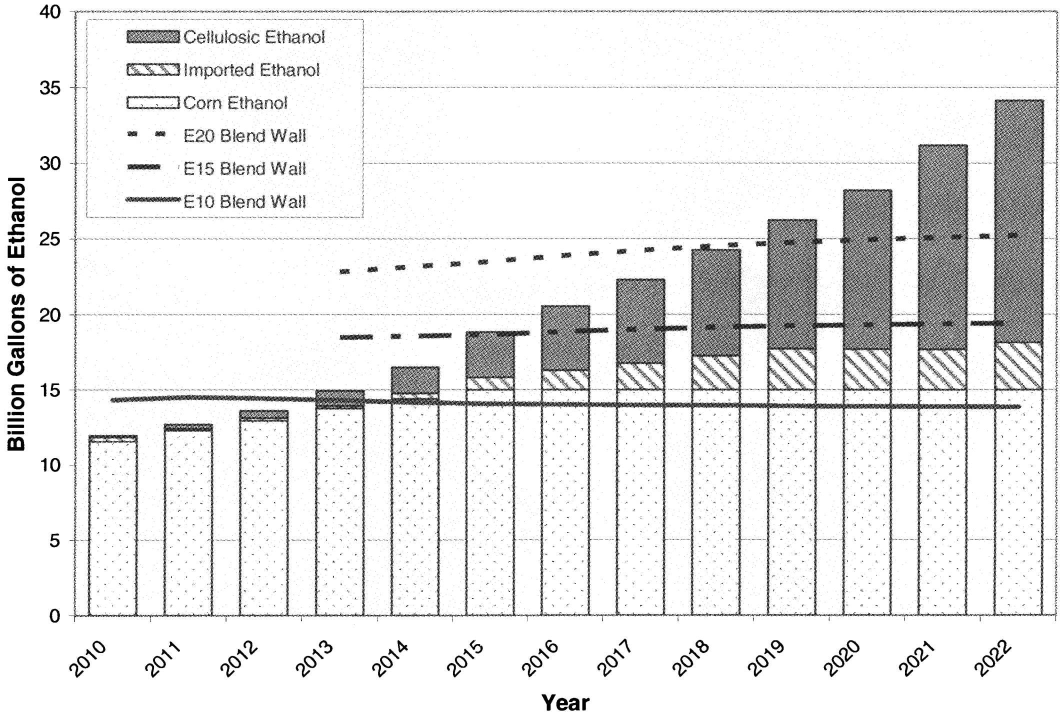
[243] Gas Plus, Inc. submitted an application for a 211(f)(4) waiver for E10 which was granted, see 44 FR 20777 (April 6, 1979).

[244] EPA has expressed what such a waiver testing program might look like, see Karl Simon, ''Mid Level Ethanol Blend Experimental Framework: Epa Staff Recommendations,'' June 2008, and Ed Nam ''Vehicle Selection & Sample Size Issues for Catalyst and Evap Durability Testing,'' November 2008, in the docket (EPA–HQ–OAR–2005–0161).

[245] Effects of Intermediate Ethanol Blends on Legacy Vehicles and Small Non-Road Engines, Report 1, Prepared by Oak Ridge National Laboratory for the Department of Energy, October 2008.

[246] Results for other cases are discussed in Section 1.7.1.3 of the DRIA.

Figure V.D.3-1
Max E15/E20 Ethanol Consumption Compared to RFS2 Requirements



As shown in Figure V.D.2–2, in this optimistic phase-in scenario, adding E15 could postpone the blend wall by about three years to 2016 and adding E20 could postpone it another three years to 2019. Although mid-level ethanol blends will fall short of meeting the RFS2 requirements, they could provide interim relief while the county ramps up E85/FFV infrastructure and/or finds other non-ethanol alternatives (e.g., cellulosic diesel or biobutanol) to reach the RFS2 volumes.

Our nation's whole system of gasoline fuel regulation, fuel production, fuel distribution, and fuel use is built around gasoline with ethanol concentrations limited to E10. As a result, while a waiver may legalize the use of mid-level ethanol blends under the CAA, there are a number of other actions that would have to occur to bring mid-level blends to retail. The time needed to take these actions could delay the penetration of mid-level ethanol blends into the market. The CAA only provides a 1 pound RVP waiver for ethanol blends of 10 volume percent or less. Lacking such an RVP waiver, a special low-RVP gasoline blendstock would be needed at terminals to allow the formulation of mid-level ethanol blends that are complaint with EPA RVP requirements. Providing such a separate gasoline blendstock would present significant logistical challenges and costs to the fuel distribution system.[247] A number of changes would be needed to EPA regulations including those pertaining to reformulated gasoline, anti-dumping, and gasoline deposit control additives to accommodate and mid-level ethanol blends. Such changes would need to be made through the notice and comment process similar to today's action. In addition, most states require that fuel comply with the applicable ASTM International (formally known as the American Standards for Testing and Materials) specification. The development of an ASTM International specification for mid-level ethanol blends through an industry consensus process is currently being initiated.

There are a number of requirements regarding the fire and leak protection safety of retail fuel dispensing and storage equipment. The Occupational Safety and Health Administration (OSHA) requires that retail fuel handling equipment be listed with an independent standards body such as Underwriters Laboratories (UL). No independent standards body has listed fuel handling equipment for mid-level ethanol blends. Furthermore, UL has stated that it would not expand listings for in-use fuel retail equipment originally listed for E10 blends to cover greater than E10 blends.[248] EPA's Office of Underground Storage Tanks (OUST) requires that UST systems must be compatible with the fuel stored in the system. These requirements pertain to all components of the system including the storage tank, connecting piping, pumps, seals and leak detection equipment.

States typically adopt fire safety codes from either the National Fire Protection Association (NFPA) or the International Code Council (ICC). These organizations currently do not have provisions that would allow the mid-level ethanol blends to be stored/dispensed from existing equipment at retail. Local safety officials (e.g. fire marshals) referred to as ''Authorities Having Jurisdiction'' (AHJ's) often require a UL certification for fuel retail storage/dispensing equipment although some will accept

[247] It may be possible for refiners to formulate a gasoline blendstock that would be suitable for manufacturing mid-level ethanol blends and E10 at the terminal. While this would avoid the logistical problems associated with maintaining separate blendstocks, there could be significant additional refining costs.

[248] UL stated that they have data which indicates that the use of fuel dispensers certified for up to E10 blends to dispense blends up to a maximum ethanol content of 15 volume percent would not result in critical safety concerns (*http://www.ul.com/newsroom/newsrel/nr021909.html*). Based on this, UL stated that it would support authorities having jurisdiction who decide to permit legacy equipment originally certified for up to E10 blends to be used to dispense up to 15 volume percent ethanol. The UL announcement did address the compatibility of underground storage tank systems with greater than E10 blends.

other substantiation of equipment safety such as a manufacture certification. Fuel retailers must also satisfy the requirements of the insurance company that they are insured through which may be more stringent than the legal requirements. Given the liability concerns associated with leaks from underground storage tanks, these issues have to be resolved in order to facilitate the widespread use of mid-level ethanol blends.

The Department of Energy and EPA are currently working with industry to evaluate what changes may be necessary to underground storage tank systems, fuel dispensers, and refueling vapor recovery equipment at fuel retail facilities to handle a mid-level ethanol blend. If existing equipment proves tolerant to a mid-level ethanol blend, this could substantially facilitate its introduction at retail. If the data supports the suitability of legacy retail equipment to store/dispense a mid-level blend, then the process of seeking acceptance by the standard bodies discussed above could commence. The normal processes used by these standards bodies can be lengthy. For example, the NFPA has a 3 year cycle for evaluating changes to its codes with proposals for the current cycle due this June. Thus, apart from the need to technically evaluate the suitability of legacy retail equipment to handle a mid-level ethanol blend, the need to secure recognition from standards bodies could delay the introduction of a mid-level ethanol blend at retail should a waiver be granted by EPA.

If some components of the above-ground existing retail hardware are found to be incompatible with a mid-level ethanol blend, it may be possible for them to be replaced through normal attrition. For example the ''hanging hardware'' which includes the nozzle and hose from the dispenser is typically replaced every 3 to 5 years. It is also possible that only minor changes might be needed to equipment that has a longer service life which might be accomplished without too much difficulty/cost. However, if extensive new equipment is needed and particularly if this involves the breaking of concrete, we believe that it is unlikely that fuel retailer would opt to install equipment specifically for a mid-level ethanol blend given the projected future need for retail equipment capable of handling E85.[249]

Finally, all vehicles and nonroad equipment currently in use are only warranted for ethanol levels not exceeding E10 (except for FFVs), and the owner's manuals are written to reflect this. Before widespread acceptance of mid-level ethanol blends by consumers can occur, these warranty issues would need to be addressed.

c. Partial Waiver for Mid-Level Blends

CAA section 211(f)(4), the waiver provision, states that the Administrator may grant a fuel waiver if a fuel manufacturer can demonstrate that the fuel ''will not cause or contribute to a failure of any emission control device or system (over the useful life of the motor vehicle, motor vehicle engine, nonroad engine or nonroad vehicle in which such device or system is used) to achieve compliance by the vehicle or engine with the emission standards with respect to which it has been certified.'' For reasons discussed below, it may be possible that these criteria for a mid-level blend waiver may be met for a subset of gasoline vehicles or engines but not for all gasoline vehicles or engines. The waiver criteria are applied over the useful life of ''the motor vehicle, motor vehicle engine, nonroad engine or nonroad vehicle in which such device or system is used.'' Assuming the criteria is met for a certain subset of vehicles, and that adequate measures could be put in place to ensure that a waiver fuel were only used in that subset of vehicles or engines, one interpretation of this provision is that the waiver could apply only to that subset of vehicles or engines.

One potential outcome from a review of the entire body of scientific and technical information available may be an indication that mid-level ethanol blends could meet the criteria of a section 211(f)(4) waiver for some vehicles and engines but not for others. It may be that certain vehicles and engines operate as intended using mid-level blends but others may be more susceptible to emissions increases or durability problems. For example, vehicles or engines without newer technology that do not readily adjust for the higher oxygen level in the fuel may experience problems, while newer technology vehicles such as those meeting our Tier 2 standards may be able to adjust for such changes as a result of more advanced emissions and fuel control equipment. Nonroad engines, which are typically small, are likely to be most susceptible given the less sophisticated technology associated with such engines. Given this potential outcome, EPA requests comment on all aspects, both legal and technical, as to the possibility that a section 211(f)(4) waiver might be granted, in a partial way with conditions, such that the use of mid-level blends would be restricted to a subset of the gasoline vehicles or engines covered by the waiver provision, while those nonroad engines and vehicles not covered by the waiver would continue using fuels with blends no greater than E10.

Any waiver approval, either fully or partially, is likely to elicit a market response to add E15 blends to E10 and E0 blends in the marketplace, rather than replace them. Thus consumers would merely have an additional choice of fuel.

Experience in past fuel programs has shown that even with consumer education and fuel implementation efforts, there sometimes continues to be public concern for new fuel requirements. Several examples include the phasedown of the amount of lead allowed in gasoline in the 1980s and the introduction of reformulated gasoline (RFG) in 1995. Some segments of the public were convinced that the new fuels caused vehicle problems or decreases in fuel economy. Although substantial test data proved otherwise, these concerns lingered in some cases for several years. As a direct result of these experiences, EPA wants to be assured that prior to potentially granting a waiver for mid-level blends, sufficient testing has been conducted to demonstrate the compatibility of a waiver fuel with engine, fuel and emission control system components.

EPA has previously granted waivers with certain restrictions or conditions. Among other things, these restrictions have included requiring fuels to meet certain voluntary consensus-based gasoline standards such as those developed by the American Society of Testing and Materials (ASTM standards), requirements that precautions be taken to prevent using the waiver fuel as a base fuel for adding oxygenates, and that certain corrosion inhibitors be utilized when producing the waived fuel.[250] However, in those waivers, the conditions placed upon the fuel manufacturer were directly related to manufacturing the fuel itself. Here, the conditions placed upon the fuel manufacturer would be on the use of the fuel in certain vehicles or engines. In other words, the fuel manufacturer would have to ensure that the mid-level blend was only used in that particular subset of vehicles or engines to be able to legally manufacture and sell the fuel

[249] As discussed previously, significant penetration of E85 is projected to be needed to facilitate the use of the volumes of ethanol we project would be needed to satisfy the requirements of the EISA.

[250] *See,* for example, 53 FR 3636, February 8, 1988, and 53 FR 33846, September 1, 1988.

under the terms of the waiver. Since it would become the fuel manufacturer's responsibility to prevent misfueling, the following discussion highlights some of the ideas that the fuel manufacturer could implement, based on particular subsets of vehicles,[251] to prevent misfueling.

If a partial waiver covered only newly manufactured vehicles, methods focused on the manufacturing of the vehicle could be utilized to inform the buyer that the vehicle was capable of operating on the waiver fuel. In this case, approaches such as the use of vehicle fueling inlet labels and owner's manuals could be utilized in tandem with retail station fuel dispenser labels. Such an approach depends on the attention of the vehicle operator to ensure compliance with the waiver. Additionally, retail station attendants could be trained to provide guidance to operators on which vehicles are covered under the waiver.

If only vehicles of certain model years were covered, owners would know if they could utilize the mid-level blends simply by knowing the model year (again, in tandem with pump labeling). Alternatively, if some portion of the existing fleet, not based upon model-year (such as vehicles meeting EPA Tier 2 emission standards), would also be covered, the approach would have to include some means by which the operator of such a vehicle would be made aware that the vehicle being fueled was covered or not covered by the waiver. Such an approach would likely involve notification of owners of covered vehicles, through direct contact or education campaigns, and would likely require the assistance of the vehicle manufacturers. This approach, as with other approaches, would require pump labeling.

Other approaches may bring about tighter control of misfueling situations but may present additional challenges. For example, one approach might be to provide owners of covered vehicles with a transaction card similar to a credit card that could be swiped at the dispenser to allow for the dispensing of a waived mid-level blend. Presumably, software and/or hardware at dispensing pumps may be able to be adjusted to accommodate such an approach. Some retail station chains have already utilized transponder mechanisms to record sales. Similar transponder systems could be utilized in place of transaction cards.

The above discussion is not meant to be an exhaustive list of possible approaches for ensuring compliance with a partial waiver, nor does it explore all the facets of any single approach. EPA recognizes that there may be legal and practical limitations on what a fuel manufacturer may be able to do to ensure compliance with the conditions of the partial waiver. EPA has not previously imposed this type of ''downstream'' condition on the fuel manufacturer as part of a section 211(f)(4) waiver. EPA does, however, have experience with compliance problems occurring when two types of gasoline have been available at service stations. Beginning in the mid-1970s with the introduction of unleaded gasoline and continuing into the 1980s as leaded gasoline was phased out, there was significant intentional misfueling by consumers. At the time most service stations had pumps dispensing both leaded and unleaded gasoline and a price differential as small as a few cents per gallon was enough to cause some consumers to misfuel. Higher price differentials could occur if, as expected, mid-level ethanol blends were to be marketed as the regular grade and E0 or E10 as the premium grade. The Agency seeks comment regarding whether this is a reasonable or practical condition for this type of waiver. EPA acknowledges that the issue of misfueling would be challenging in a situation where a partial waiver is granted. Therefore, EPA solicits comments on what measures a fuel manufacturer, EPA or others in the gasoline distribution network could take for ensuring compliance with a partial waiver.

While EPA has not analyzed the specific cost of a conditional waiver, such a waiver would likely carry a cost similar to the costs described above in Section V.D.3.b. Because existing equipment in retail stations is certified by Underwriters Laboratories only up to ten percent ethanol, existing equipment would need to be evaluated for its acceptability for use with mid-level blends (and deemed to be acceptable if possible) or it would have to be modified/replaced before any ethanol blend greater than ten percent could be effectuated in the marketplace.[252] If existing retail equipment is found not to be acceptable for storing/dispensing mid-level blends, the aforementioned infrastructure challenges would be present and additional costs would be associated with measures adopted for the prevention of releases due to material incompatibility, as well as those associated with misfueling. EPA therefore seeks comment on the compatibility of the existing retail fuel storage/dispensing equipment with mid-level ethanol blends. Further, adoption of such a waiver would mean that fewer vehicles/engines would be able to utilize mid-level blends and, therefore, the full impact of mid-level blends on the E10 blend wall under such a scenario would not be as significant as full unrestricted utilization of such blends.

d. Non-Ethanol Cellulosic Biofuel Production

While our analysis describes possible pathways by which the market could meet the RFS2 requirements with 34 billion gallons of ethanol as E10 and E85, our analysis of the required FFV and E85 infrastructure growth as well as the required changes to the E10/E85 price relationship suggests some inherent challenges. Furthermore, we conclude that the introduction of mid-level ethanol blends (contingent upon waiver approval) would by itself not allow the country to achieve the RFS2 standards. Another means of achieving the RFS2 volume requirements would be through the introduction of non-ethanol cellulosic biofuels. The growing spread in gasoline and diesel pricing implies that we are currently moving in the direction of being oversupplied with gasoline and undersupplied with diesel.[253] As such, it makes sense that the market might preferentially investigate diesel fuel replacements, e.g., cellulosic diesel via Fischer-Tropsch synthesis, pyrolysis, or catalytic depolymerization. These fuels would meet the definition of cellulosic biofuel (as well as advanced biofuel) under the proposed RFS2 program and help reduce the ethanol blend wall impacts associated with this rule. Although for our analysis we assumed that the cellulosic biofuel standard would be met with ethanol, the market could choose a significant volume of other non-ethanol renewable fuels. DOE and other agencies are currently providing grants to support critical

[251] Although it is not possible at this time to know the contours of a partial waiver with conditions, or even if one might be appropriate, the remainder of this discussion will refer only to vehicles covered by the waiver (and not engines) since newer vehicles are more likely to have more sophisticated emissions and fuel control equipment, while certain engines might be more affected for the reasons stated above.

[252] See previous discussion in Section V.D.3.b of this preamble regarding the issues that would need to be addressed to facilitate the introduction of mid-level ethanol blends at retail.

[253] According to EIA, gasoline and diesel prices were pretty similar on average for a decade from 1995–2004. However, over the past four years, diesel prices have begun to track consistently higher than gasoline prices. To date in 2008, diesel has been priced more than $0.50/gallon higher than gasoline on average. *Source: http://tonto.eia.doe.gov/oog/info/gdu/gasdiesel.asp.*

research into these second-generation cellulosic feedstock conversion technologies. DOE is also providing loan guarantees to help with the commercialization of such technologies. For more information on non-ethanol cellulosic biofuels, refer to Section V.A. or Section 1.4.3 of the DRIA.

e. Measurement Tolerance For E10

Some stakeholders have suggested that the implementation of a tolerance in the measurement of the ethanol content of gasoline could allow more ethanol to be used in existing vehicles without the need for a formal waiver and without the need for more FFVs. Such a tolerance could allow ethanol contents slightly higher than 10 volume percent while still treating such blends as meeting the 10 volume percent limitation on the ethanol content of gasoline.

Although there is no explicit written precedent for permitting ethanol contents higher than 10 vol%, some have speculated that current vehicles would not exhibit any noticeable change in performance, durability, or emissions if a small measurement tolerance for ethanol content of gasoline were allowed. The current specified test method for oxygen content ASTM D–5599–00 includes estimates of the measurement reproducibility that could be used to inform the determination of an appropriate tolerance for ethanol content in gasoline. For instance, based on the provided reproducibility, a measurement as high as 11 vol% ethanol in gasoline might be possible for gasoline that was blended to meet a 10 vol% ethanol requirement. Historically, however, EPA has always enforced the 10 vol% waiver at the 10 vol% level without any tolerance.

The 1978 gasohol waiver application requested a blend of 90% unleaded gasoline and 10% anhydrous ethanol. Although not specified in the application, the convention and the practical approach for blending ethanol into gasoline in 1978 was by volume, and it has continued to be by volume. Thus, the limit on ethanol in gasoline under the waiver is 10% by volume. This is approximately 3.5% oxygen by weight. The waiver request did not apply to a level of ethanol in gasoline beyond 10%, and since the application was approved by default after 180 days due to the fact that the Administrator did not make an explicit decision in this timeframe, there is no formal approval that could have indicated what measurement tolerances might have been acceptable. Thus it has historically been enforced at the 10 vol% limit without any enforcement tolerance.

However, parties who have raised this option have suggested that the Agency's previous treatment of the oxygenate content of gasoline may provide a precedent that would allow for a higher measurement tolerance for ethanol content.

Prior to and after 1981, several waivers issued by the Agency allowed the use of various alcohols and ethers in unleaded gasoline. In 1981, the ''substantially similar'' interpretive rule for unleaded gasoline allowed certain alcohols and ethers at up to 2.0% oxygen by weight. In 1991 the limit was increased to 2.7% oxygen by weight. For each of these waivers, the unleaded gasoline base to which the oxygenate was to be added was to be initially free of oxygenate. With the exception of ethanol, oxygenates, mostly MTBE, were blended at the refinery, with the refiner in control of the gasoline used for blending. This enabled the refiner to ensure that it was free of oxygenate prior to blending. Ethanol was primarily blended at terminals. In order to ensure that gasoline blended with ethanol at the terminal was free of other oxygenates, the ethanol blender first had to check for the presence of other oxygenates in the base gasoline. In the mid-1980's ethanol blenders informed EPA that they were having difficulty finding oxygenate-free gasoline. Much of gasoline had at least trace amounts of MTBE due to commingling of gasolines with different oxygenates in the fungible pipeline system. In order to continue to allow the blending of ethanol up to the 10 vol% limit, EPA issued a letter stating that it would not consider it to be a violation of the ethanol sub-sim waiver if up to 10% by volume ethanol were added to unleaded gasoline containing no more than 2% by volume MTBE. However, the MTBE must have been present only as a result of commingling during storage or transport and not purposefully added as an additional component to the ethanol blend.

Subsequently, two other statements by EPA provided guidance on the allowable oxygen content of oxygenated fuels. For instance, in a memorandum dated October 5, 1992, EPA provided interim guidance for states that allowed averaging programs.[254] This guidance allowed the oxygen content of ethanol to be as high as 3.8% by weight, but did not indicate that the ethanol concentration could be higher than 10 vol%. Also, in a 1995 RFG/Anti-dumping Q&A it was noted that the maximum oxygen range for the simple and complex models was 4.0% by weight. This range was implemented to once again continue to allow the blending of ethanol up to the 10 vol% limit in cases where an extremely low gasoline density might increase the calculated weight percent oxygen content for E10 above the more typical 3.5–3.7 wt% range.

Although we acknowledge that the currently specified test method ASTM D–5599–00 includes some variability, ethanol is different than many other fuel properties and components that are controlled in other fuel programs in one important respect. Fuel properties such as RVP, and components such as sulfur and benzene, are natural characteristics of gasoline as a result of the chemical nature of crude oil and the refining process. Their level or concentration in gasoline is unknown until measured, and then is dependent upon accuracy of the test method. In contrast, ethanol is intentionally added in known amounts using equipment designed to ensure a specific concentration within a small fraction of one percent. Parties that blend ethanol into gasoline therefore have precise control over the final concentration. Thus, a measurement tolerance for ethanol would be less appropriate than measurement tolerances for other fuel properties and components.

We request comment on whether a measurement tolerance should be allowed for the ethanol content of gasoline, the basis for such a tolerance, and what tolerance if any would be appropriate. We also request comment on whether such a tolerance would fit within the existing Underwriters Laboratories, Inc. (UL) approval for the safety of equipment at refueling stations, including underground storage tanks, pumps, piping, seals, etc.

f. Redefining ''Substantially Similar'' to Allow Mid-Level Ethanol Blends

Section 211(f)(1) prohibits the introduction into commerce, or increase in the concentration in use of, gasoline or gasoline additives for use in motor vehicles unless they are substantially similar to the gasoline or gasoline additives used in the certification of new motor vehicles or motor vehicle engines. EPA may grant a waiver of this prohibition under section 211(f)(4) of the Clean Air Act provided that the fuel or fuel additive ''will not cause or contribute to a failure of any emission control device or system (over the useful life of the motor vehicle, motor vehicle engine, nonroad engine or nonroad vehicle in which the device or system

[254] Memorandum from Mary T. Smith, Director of the Field Operations and Support Division, to State/Local Oxygenated Fuels Contacts, October 5, 1992. Subject: ''Testing Tolerance''.

is used) to achieve compliance by the vehicle or engine with the emission standards to which it has been certified.''

EPA first interpreted the term ''substantially similar'' for unleaded gasoline and its additives in 1978.[255] Recognizing that this interpretation was too limited, EPA updated it in 1980, and again in 1981.[256] EPA set the limits contained in the interpretation based on the physical and chemical similarities of the fuel or fuel additives to those used in the motor vehicle certification process. EPA also considered information available regarding the emission effects that such fuels and additives would exhibit relative to the emissions performance of the certification fuels and fuel additives. The 1981 interpretative rule identified the characteristics and specifications that EPA determined would make a fuel or fuel additive ''substantially similar'' to those used in certification. Under this rule, a fuel or fuel additive would be considered substantially similar if it satisfied certain limits on fuel and fuel additive composition, did not exceed a maximum allowable oxygen content of fuel at 2.0% by weight, and met certain ASTM specifications. Comments on this interpretative rule requested that EPA increase the maximum oxygen concentration up to 3.5% oxygen by weight, but EPA rejected this recommendation, stating that it would keep the limit at 2.0% because of concerns over emissions, material compatibility, and drivability from use of various alcohols at higher oxygen contents.

In 1991, EPA amended the interpretive rule by revising the oxygen content criteria to allow fuels containing aliphatic ethers and/or alcohols (excluding methanol) to contain up to 2.7% by weight oxygen.[257] EPA based this increase in the oxygen content on its review of information on a wide variety of alcohol and ether blends, leading it to determine that ''unleaded gasolines with such oxygen content are chemically and physically substantially similar to, and have been shown to have emissions properties substantially similar to, unleaded gasolines used in light-duty vehicle certification.'' [258] Finally, in 2008, EPA amended the interpretive rule to allow flexibility for the vapor/liquid ratio specification for fuel introduced into commerce in the state of Alaska to improve cold starting for vehicles during the winter months in Alaska.[259] Thus the ''substantially similar'' interpretive rule for unleaded gasoline presently allows oxygen content up to 2.7% by weight for certain ethers and alcohols.

A waiver of the substantially similar prohibition was provided by operation of law in 1979 under CAA section 211(f)(4), allowing a gasoline-alcohol fuel blend with up to 10% ethanol by volume (E10) (''E10 Waiver''). E10 has an oxygen content which typically ranges between 3.5 and 3.7% by weight, depending on the specific gravity of the gasoline. Any ethanol blends with greater than 10% ethanol by volume would have an oxygen content which exceeds the 2.7% by weight allowed under the current interpretation of ''substantially similar.'' Therefore, under the 1991 interpretive rule, mid-level ethanol blends would not be considered substantially similar and would require a CAA section 211(f)(4) waiver.

It has been suggested to EPA that we should update the interpretive rule such that mid-level ethanol blends would be considered substantially similar. As in the past, this would involve consideration of the physical and chemical similarities of such mid-level blends to fuels used in the certification process, as well as information about the expected emissions effects of such mid-level blends.[260] EPA invites comment on whether mid-level blends of ethanol are physically and chemically similar enough to the fuels used in the motor vehicle certification process such that they could be considered ''substantially similar'' to the certification fuels used by EPA. With respect to the emissions effects of mid-level blends on emissions performance, EPA recognizes that there may be different impacts depending on the kind of motor vehicle involved. For example, it has been suggested that older technology motor vehicles and engines may have emissions and durability impacts from ethanol blends higher than 10 percent, while Tier 2 and later technology vehicles—2004 and later model year vehicles—may have fewer such impacts.[261] These more recent technology vehicles represent an ever growing proportion of the in-use fleet. DOE is currently conducting various test programs to ascertain the impacts of higher level ethanol blends on vehicles and equipment.

EPA seeks comment on all of the issues involved with reconsidering its interpretation of the term ''substantially similar'' to include gasoline blended with ethanol to contain up to 4.5% oxygen by weight. If EPA revised the substantially similar interpretation in this manner, gasoline blended with up to 12% ethanol by volume (E12) would be considered ''substantially similar.'' [262] Given the possibility, based upon engineering judgment, of a varying impact of a mid-level ethanol blends on different technology vehicles, EPA invites comment on limiting such an interpretation to gasoline intended for use in Tier 2 and later motor vehicles. We estimate that defining E12 as ''substantially similar'' for Tier 2 and later motor vehicles could delay the saturation of the gasoline market with ethanol for up to a year, allowing for more comprehensive testing on higher blend levels to be carried out. However, before EPA could determine whether it was appropriate to revise the interpretation of ''substantially similar'' for gasoline to include gasoline-alcohol fuels blended with up to 12% ethanol, information would need to be provided to EPA that would allow for a robust assessment of the impact of E12 over the full useful life of Tier 2 and later motor vehicles addressing emissions (both tailpipe and evaporative emissions), materials compatibility, and drivability. Furthermore, E12 would still need to fulfill registration requirements (i.e. speciation and health effects testing found at 40 CFR 79.52 and 40 CFR 79.53).

EPA also seeks comments on additional regulatory and implementation issues that would arise as a result of changing the ''substantially similar'' definition to allow for E12. These issues as identified for mid-level blends in the discussion in Section V.D.3.b include, but are not necessarily limited to, the applicability of the 1.0 psi RVP waiver with regard to 10% ethanol blends found at 40 CFR

[255] 43 FR 11258 (March 17, 1978), 43 FR 24131 (June 2, 1978).

[256] 45 FR 67443 (October 10, 1980), 46 FR 38582 (July 28, 1981).

[257] 56 FR 5352 (February 11, 1991).

[258] 56 FR at 5353.

[259] 73 FR 22277 (April 25, 2008).

[260] One point to be clear on is that the substantially similar provision relates to fuels used in certification. It is not an issue of whether mid-level blends are substantially similar to a fuel that has received a waiver of this prohibition. See 46 FR 38582, 38583 (July 28, 1981). The fuels used in certification include the test fuels used for exhaust testing, test fuels for evaporative emissions testing, and the fuels used in the durability process.

[261] It has also been suggested that nonroad engines and equipment may experience greater emissions effects and durability problems when using mid-level blends.

[262] As mentioned earlier, EPA has typically used the oxygen weight percent convention when interpreting the ''substantially similar'' provision. A change in the ''substantially similar'' interpretation to allow for up to 4.5% oxygen by weight in the form of ethanol would essentially accommodate ethanol blends up to 12% by volume since the vast majority of gasolines blended at 12% by volume ethanol would not exceed this oxygen weight percent limit.

80.27(d), Clean Air Act section 211(h); the accommodation of ethanol blends in making calculations utilizing the complex model for reformulated and conventional gasoline at 40 CFR 80.45; and detergent certification requirements found at 40 CFR 80 (Subpart G). Emissions speciation and health effects testing is required for oxygenate-specific blends under 40 CFR 79 (Subpart F). Such testing is currently underway for 10% ethanol blends but not for ethanol levels higher than 10 percent. Additionally, if E12 was allowed under the ''substantially similar'' definition, presumably such a blend would have to meet one of the volatility classes of ASTM D4814–88, which is not now the case with some blends of 10% ethanol blended under the E10 Waiver. Any change in the allowable maximum ethanol level in motor fuels will impact these and, potentially, other motor fuel regulations.

Furthermore, there are also implications beyond EPA's motor fuel regulations. Existing equipment in retail stations is certified by Underwriters Laboratories only up to 10% ethanol. Thus, either existing equipment would need to be recertified for E12 (if possible) or it would have to be replaced before E12 could be effectuated in the marketplace. In addition, the substantially similar prohibition applies to the fuel manufacturer, and if the reinterpretation only applied to gasoline used with Tier 2 and later motor vehicles, then the manufacturer of a mid-level blend could not introduce it into commerce for use with any other motor vehicles. This means that the fuel distribution system would need to be structured in such a way that the fuel manufacturer could appropriately ensure that the fuel was only used in Tier 2 or later motor vehicles. Preventing the misfueling of mid-level blends into vehicles and engines not specified in the interpretive rule, and ensuring the availability of fuels for other vehicles and engines, poses a major problem with reinterpreting ''substantially similar'' to include mid-level blends with a restriction for use in Tier 2 and later motor vehicles. (For a more detailed discussion on this issue, see Section V.D.3.c above). We seek comment on these logistical and regulatory concerns as well.

VI. Impacts of the Program on Greenhouse Gas Emissions

A. Introduction

Lifecycle modeling, often referred to as fuel cycle or well-to-wheel analysis, assesses the net impacts of a fuel throughout each stage of its production and use including production/extraction of the feedstock, feedstock transportation, fuel production, fuel transportation and distribution, and tailpipe emissions.[263] This section describes and seeks comment on the methodology developed by EPA to determine the lifecycle greenhouse gas (GHG) emissions of biofuels fuels as required by EISA as well as the petroleum-based transportation fuels being replaced. While much of the discussion below focuses on those portions of lifecycle assessment particularly important to biofuel production, the basic methodology was the same for analyzing both petroleum-based fuels and biofuels. This methodology was utilized to determine which biofuels (both domestic and imported) qualify for the four different GHG reduction thresholds established in EISA. This threshold assessment compares the lifecycle emissions of a particular biofuel including its production pathway against the lifecycle emissions of the petroleum-based fuel it is replacing (e.g., ethanol replacing gasoline or biodiesel replacing diesel). This section also seeks comment on the Agency's proposal to utilize the discretion provided in EISA to adjust these thresholds downward should certain conditions be met. We also explain how feedstocks and fuel types not included in our analysis will be addressed and incorporated in the future. The overall GHG benefits of the RFS program, which are based on the same methodology presented here, are provided in Section VI.F.

As described in detail below, EPA has analyzed the lifecycle GHG impacts of the range of biofuels currently expected to contribute significantly to meeting the volume mandates of EISA through 2022. In these analyses we have used the best science available. Our analysis relies on peer reviewed models and the best estimate of important trends in agricultural practices and fuel production technologies as these may impact our prediction of individual biofuel GHG performance through 2022. We have identified and highlighted assumptions and model inputs that particularly influence our assessment and seek comment on these assumptions, the models we have used and our overall methodology so as to assure the most robust assessment of lifecycle GHG performance for the final rule.

EPA believes that compliance with the EISA mandate—determining the aggregate GHG emissions related to the full fuel lifecycle, including both direct emissions and significant indirect emissions such as land use changes—makes it necessary to assess those direct and indirect impacts that occur not just within the United States and also those that occur in other countries. This applies to determining the lifecycle emissions for petroleum-based fuels, to determine the baseline, as well as the lifecycle emissions for biofuels. For biofuels, this includes evaluating significant emissions from indirect land use changes that occur in other countries as a result of the increased production and importation of biofuels in the U.S. As detailed below, we have included the GHG emission impacts of international indirect land use changes. We recognize the significance of including international land use emissions impact and in our analysis presentation we have been transparent in breaking out the various sources of GHG emissions so that the reader can readily see the impact of including international land use impacts.

In addition to the many technical issues addressed in this proposal, this section also discusses the emissions decreases and increases associated with the different parts of the lifecycle emissions of various biofuels, and the timeframes in which these emissions changes occur. Determining a single lifecycle value that best represents this combination of emissions increases and decreases occurring over time led EPA to consider various alternative ways to analyze the timeframe of emissions related to biofuel production and use as well as options for adjusting or discounting these emissions to determine their net present value. Several variations of time period and discount rate are discussed. The analytical time horizon and the choice whether to discount GHG emissions and, if so, at what appropriate rate can have a significant impact on the final assessment of the lifecycle GHG emissions impacts of individual biofuels as well as the overall GHG impacts of these EISA provisions and this rule.

We believe that our lifecycle analysis is based on the best available science, and recognize that in some aspects it represents a cutting edge approach to addressing lifecycle GHG emissions. Because of this, varying degrees of uncertainty are in our analysis. For this proposal, we conducted a number of

[263] In this preamble, we are considering ''lifecycle analysis'' in the context of estimating GHG emissions, as required by EISA. More generally, the term ''lifecycle analysis'' or ''assessment'' has been defined as an evaluation of all the environmental impacts across the range of media/exposure pathways that are associated with a ''cradle to grave'' view of a product or set of policies. For more information on this broader context, please see the 2006 EPA publication ''Life Cycle Assessment: Principles and Practice (EPA/600/R–06/060).

sensitivity analyses which focus on key parameters and demonstrate how our assessments might change under alternative assumptions. By focusing attention on these key parameters, the comments we receive as well as additional investigation and analysis by EPA will allow narrowing of uncertainty concerns for the final rule. In addition to this sensitivity analysis approach, we will also explore options for more formal uncertainty analyses for the final rule to the extent possible.

Because lifecycle analysis is a new part of the RFS program, in addition to the formal comment period on the proposed rule, EPA is making multiple efforts to solicit public and expert feedback on our proposed approach. As discussed in Section XI, EPA plans to hold a public workshop during the comment period focused specifically on our lifecycle analysis to help ensure full understanding of the analyses conducted, the issues addressed and options that should be considered. We expect that this workshop will help ensure that we receive the most thoughtful and useful comments to this proposal and that the best methodology and assumptions are used for calculating GHG emissions impacts of fuels for the final rule. Additionally we will conduct peer-reviews of key components of our analysis. As explained in more detail in the following sections, EPA is specifically seeking peer review of: Our use of satellite data to project future land use changes; the land conversion GHG emissions factors estimated by Winrock; our estimates of GHG emissions from foreign crop production; methods to account for the variable timing of GHG emissions; and how models are used together to provide overall lifecycle GHG estimates.

The regulatory purpose of the lifecycle greenhouse gas emissions analysis is to determine whether renewable fuels meet the GHG thresholds for the different categories of renewable fuel.

1. Definition of Lifecycle GHG Emissions

The GHG provisions in EISA are notable for the GHG thresholds mandated for each category of renewable fuel and also the mandated lifecycle approach to those thresholds. Renewable fuel must, unless ''grandfathered'' as discussed in Section II.B.3., achieve at least 20% reduction in lifecycle greenhouse gas emissions compared to the average lifecycle greenhouse gas emissions for gasoline or diesel sold or distributed as transportation fuel in 2005. Similarly, biomass-based diesel and advanced biofuels must achieve a 50% reduction, and cellulosic biofuels a 60% reduction, unless these thresholds are adjusted according to the provisions in EISA. To EPA's knowledge, the GHG reduction thresholds presented in EISA are the first lifecycle GHG performance requirements included in federal law. These thresholds, in combination with the renewable fuel volume mandates, are designed to ensure significant GHG emission reductions from the use of renewable fuels and encourage the use of GHG-reducing renewable fuels.

The definition of lifecycle greenhouse gas emissions established by Congress is also critical. Congress specified that:

> The term 'lifecycle greenhouse gas emissions' means the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes), as determined by the Administrator, related to the full fuel lifecycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer, where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential.[264]

This definition requires EPA to look broadly at lifecycle analyses and to develop a methodology that accounts for all the important factors that may significantly influence this assessment, including the secondary or indirect impacts of expanded biofuels use. EPA's analysis described below indicates that the assessment of lifecycle GHG emissions for biofuels is significantly affected by the secondary agricultural sector GHG impacts from increased biofuel feedstock production (e.g., changes in livestock emissions due to changes in agricultural commodity prices) and also by the international impact of land use change from increased biofuel feedstock production. Thus, these factors must be appropriately incorporated into EPA's lifecycle methodology to properly assess full lifecycle GHG performance of biofuels in accordance with the EISA definition.

2. History and Evolution of GHG Lifecycle Analysis

Traditionally, the GHG lifecycle analysis of fuels has involved calculating the emissions associated with each individual stage in the production and use of the fuel (e.g., growing or extracting the feedstock, moving the feedstock to the processing plant, processing the feedstock into fuel, moving the fuel to market, and combusting the fuel.) EPA used this approach for the lifecycle modeling conducted for the RFS1 program in 2005. However, it has become increasingly apparent that this type of first order or attributional lifecycle modeling has notable shortcomings, especially when evaluating the implications of biofuel policies.[265] In fact, the main criticism EPA received in reaction to our previous RFS1 lifecycle analysis was that we did not include important secondary, indirect, or consequential impacts of biofuel production and use.

Several studies and analyses conducted since the completion of RFS1 have contributed to our understanding of the lifecycle GHG emissions of biofuel production. These studies, and others, have highlighted the potential impacts of biofuel production on the agricultural sector and have specifically identified land use change impacts as an important consideration when determining GHG impacts of biofuels.[266] [267] In the meantime, the dramatic increase in U.S. production of biofuels has heightened the concern about the impacts biofuels might have on land use and has increased the importance of considering these indirect impacts in lifecycle analysis.

Based on the evolution of lifecycle analysis and the new requirements of EISA, we have developed a comprehensive methodology for estimating the lifecycle GHG emissions associated with renewable fuels. Through dozens of meetings with a wide range of experts and stakeholders, EPA has shared and sought input on this methodology. We also have relied on the expertise of the U.S. Department of Agriculture (USDA) and the Department of Energy (DOE) to help inform many of the key assumptions and modeling inputs for this analysis. Dialogue with the State of California and the European Union on their parallel, on-going efforts in GHG

[264] Clean Air Act Section 211(o)(1).

[265] *See* also, Conceptual and Methodological Issues in Lifecycle Analysis of Transportation Fuels, Mark A. Delucchi, Institute of Transportation Studies, University of California, Davis, 2004, UCD–ITS–RR–04–45 for a description of issues with traditional lifecycle analysis used to model GHG impacts of biofuels and biofuel policies.

[266] Fargione, J., J. Hill, D. Tilman, S. Polasky, and P. Hawthorne. 2008. Land clearing and the biofuel carbon debt. Science 319:1235–1238. *See http://www.sciencemag.org/cgi/reprint/319/5867/1235.pdf.*

[267] Searchinger, T., R. Heimlich, R.A. Houghton, F. Dong, A. Elobeid, J. Fabiosa, S. Tokgoz, D. Hayes, and T.-H. Yu. 2008. Use of U.S. croplands for biofuels increases greenhouse gases through emissions from land-use change. Science 319:1238–1240. *See http://www.sciencemag.org/cgi/reprint/319/5867/1238.pdf.*

lifecycle analysis has also helped inform EPA's methodology. As part of this discussion, we have identified several of the key drivers associated with these lifecycle GHG emissions estimates, including assumptions about international land use change and the timing of GHG emissions over time. The inputs we have received through these interactions are reflected throughout this section.

Specifically EPA has worked closely with the California Air Resources Board (CARB) regarding their development of transportation fuels lifecycle GHG impacts. California Executive Order S–1–07, the Low Carbon Fuel Standard (LCFS) (issued on January 18, 2007), calls for a reduction of at least 10 percent in the carbon intensity of California's transportation fuels by 2020. CARB has worked to develop lifecycle GHG impacts of different fuels for this Executive Order rulemaking. More information about this rulemaking and the lifecycle analysis conducted by California can be found at *http://www.arb.ca.gov/fuels/lcfs/lcfs.htm*. EPA will continue to coordinate with California on this rulemaking and the biofuels lifecycle GHG analysis work.

Because this lifecycle GHG emissions analysis is complex and requires the use of sophisticated computer models, we have taken several steps to increase the transparency associated with our analysis. For example, we have updated the model documentation for the Forest and Agricultural Sector Optimization Model (FASOM), which is included in the docket. In addition, we have highlighted key assumptions in FASOM and the Food and Agricultural Policy Research Institute (FAPRI) models that impact the results of our analysis. Finally, this NPRM provides an important opportunity for the Agency to present our work and to receive input from stakeholders and experts in this field. We will also continue to refine our analysis between the proposed and final rules, and we will add or update information to the docket as it becomes available.

B. Methodology

This section describes EPA's methodology for assessing the lifecycle GHG emissions associated with each biofuel evaluated as well as the petroleum-based gasoline and diesel fuel these biofuels would replace. Whereas lifecycle GHG emission methodologies have been well studied and established for petroleum-based gasoline and diesel fuel, much of EPA's work has focused on newly developing lifecycle methodologies for biofuels. Therefore, much of the following section describes the biofuels-related methodologies and identifies important issues for comment. Assessing the complete lifecycle GHG impact for each individual biofuel mandated by EISA requires that a number of key methodological issues be addressed—from the choice of a baseline to the selection of the most credible technique for predicting international land use conversion due to the increase in U.S. renewable fuels demand, to accounting for the time dimension of changes in GHG emissions. In this section, we first describe the scenarios we have analyzed for this proposal. Second, we discuss the scope of our analysis and what is included in our estimates. Third, we provide details on the tools and models we used to quantify the GHG emissions associated with the different fuels. Fourth, we discuss the uncertainties associated with lifecycle analysis and how we have addressed them. Fifth, we describe the different components of the lifecycle that we have analyzed and the key questions we have addressed in this analysis.

1. Scenario Description

To quantify the lifecycle GHG emissions associated with the increase in renewable fuel mandated by EISA, we compared the differences in total GHG emissions between two future scenarios. The first assumed a ''business as usual'' volume of a particular renewable fuel based on what would likely be in the fuel pool in 2022 without EISA, as predicted by the Energy Information Agency's Annual Energy Outlook (AEO) for 2007 (which took into account the economic and policy factors in existence in 2007 before EISA). The second assumed the higher volume of renewable fuels as mandated by EISA for 2022. For each individual biofuel, we analyzed the incremental GHG emission impacts of increasing the volume of that fuel to the total mix of biofuels needed to meet the EISA requirements. Rather than focus on the impacts associated with a specific gallon of fuel and tracking inputs and outputs across different lifecycle stages, we determined the overall aggregate impacts across sections of the economy in response to a given volume change in the amount of biofuel produced.[268]

This analysis is not a comparison of biofuel produced today versus biofuel produced in the future. Instead, it is a comparison of two future scenarios. Any projected changes in factors such as crop yields, energy costs, or production plant efficiencies, both domestically and internationally, are reflected in both scenarios. We focused our analyses on 2022 results for three reasons. First, it would require an extremely complex assessment and administratively difficult implementation program to track how biofuel production might continuously change from month to month or year to year. Instead, it seems appropriate that each biofuel be assessed a level of GHG performance that is constant over the implementation of this rule, allowing fuel providers to anticipate how these GHG performance assessments should affect their production plans. Second, it is appropriate to focus on 2022, the final year of ramp up in the required volumes of renewable fuel as this year. Assessment in this year allows the complete fuel volumes specified in EISA to be incorporated. Third, since the GHG assessment compares performance between a business as usual case and the mandated volumes case, many of the factors that change over time such as crop yield per acre are reflected in both cases. Therefore the differences in these parallel assessments are unlikely to vary significantly over time.

EPA requests comment on its proposal to adopt fixed assessments of fuels meeting the GHG thresholds based on a 2022 performance assessment. Additional information on the scenarios modeled and the supplemental analyses that will be conducted for the final rule is included in Chapter 2 of the DRIA.

In the existing Renewable Fuel Standard rules adopted in response to the Energy Policy Act of 2005, biofuels and RINs associated with them are not based on regional differences of where the feedstock was grown or the biofuel was produced. In effect, the RINs apply to a national average of the fuel type. Similarly, this proposal does not distinguish biofuel on the basis of where within the country the biofuel feedstock was grown or the biofuel produced. Thus, for example, ethanol produced from corn starch using the same production technology will receive the same GHG lifecycle assessment regardless of where the corn was grown or at what facility the biofuel was produced. There are regional differences in soil types, weather conditions, and other factors which could affect, for example, the amount of fertilizer applied and thus the GHG impact of corn production. Such factors could vary somewhat across a region, within a state and even within a county. The agricultural models used to conduct this analysis do distinguish crop production

[268] We then normalize those impacts for each gallon of fuel (or Btu) by dividing total impacts over the given volume change.

by region domestically and by country internationally. However, biofuel feedstocks such as corn or soybean oil are well traded commodities including internationally. So, for example, if corn in a certain location in Iowa is used to produce ethanol, corn from all other regions will be used to replace that corn for all its other potential uses. Therefore, it is not appropriate to ascribe the indirect affects, both domestically and internationally, to corn grown in one area differently to corn (or other biofuel feedstock) grown in another area. Our national treatment of biofuel feedstock also pertains to fuels produced in other countries. Thus for example, sugarcane-based ethanol produced in Brazil is all treated the same regardless of where the sugarcane was grown in Brazil. Nevertheless, comments are invited on the option of differentiating biofuels in the future based on the location of their feedstock production within a country.

2. Scope of the Analysis

a. Legal Interpretation of Lifecycle Greenhouse Gas Emissions

As described in VI.A.1, the definition of lifecycle greenhouse gas emissions refers to the ''aggregate quantity of GHG emissions'' that are ''related to the full fuel lifecycle.'' The fuel lifecycle includes ''all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through * * * use of the finished fuel to the ultimate consumer.'' The aggregate quantity of GHG emissions includes ''direct emissions'' and ''significant indirect emissions such as significant emission from land use changes.'' This provision is written in generally broad and expansive terms, such as ''aggregate quantity'', ''related to'', ''full fuel lifecycle'', and ''all stages'' of production and distribution. At the same time, these and other terms are not themselves defined and provide discretion to the Administrator in implementing this definition. For example, the word ''significant,'' which is used to modify ''indirect emissions,'' is not defined.

The definition includes both ''direct'' and ''significant indirect'' emissions related to the full fuel lifecycle. We consider direct emissions as those that are emitted from each stage of the full fuel lifecycle, and indirect emissions as those from second order effects that occur as a consequence of the full fuel lifecycle. For example, direct emissions for a renewable fuel would include those from the growing of renewable fuel feedstock, the distribution of the feedstock to the renewable fuel producer, the production of renewable fuel, the distribution of the finished fuel to the consumer, and the use of the fuel by the consumer as transportation fuel. Similarly, direct emissions associated with the baseline fuel would include extraction of the crude oil, distribution of the crude oil to the refinery, the production of gasoline and diesel from the crude oil, the distribution of the finished fuel to the consumer, and the use of the fuel by the consumer. Indirect emissions would include other emissions impacts that result from fuel production or use, such as changes in livestock emissions resulting from changes in livestock numbers, or shifts in acreage between different crop types. The definition of indirect emissions specifically includes ''land use changes'' which would include changes in the kind of usage that land is put to such as changes in forest, pasture, savannah, and crop use.[269]

In considering how to address land use changes in our lifecycle analysis, two distinct questions have been raised—whether to account for emissions that occur outside of the U.S., and under what circumstances land use change should properly be included in the lifecycle analysis.

On the question of considering GHG emissions that occur outside of the U.S., it is important to be clear that including such emissions in the lifecycle analysis does not exercise regulatory authority over activities that occur solely outside the U.S., and does not raise questions of extra-territorial jurisdiction. EPA's regulatory action involves classification of products either produced in the U.S. or imported into the U.S. EPA is simply assessing whether the use of these products in the U.S. satisfies requirements under the Clean Air Act for the use of designated volumes of renewable fuel, cellulosic biofuel, biomass-based diesel and advanced biofuel, as those terms are defined in the Act. Considering international emissions in determining the lifecycle GHG emissions of the domestically produced or imported fuel does not change the fact that the actual regulation of the product involves its use solely inside the U.S.

When looking at the issue of international versus domestic emissions, it is important to recognize that a large variety of different activities outside the U.S. play a major part of the full fuel lifecycle of baseline and renewable fuels. For example, for baseline fuels (i.e., gasoline and diesel fuels used as transportation fuel in 2005), GHG emissions associated with extraction and delivery of crude oil imported to the U.S. all have occurred overseas. In addition, for imported gasoline or diesel, all of the crude extraction and delivery emissions, as well as the emissions associated with refining and distribution of the finished product to the U.S., would have occurred overseas. For imported renewable fuel all of the emissions associated with feedstock production and distribution, processing of the feedstock into renewable fuel, and delivery of the finished renewable fuel to the U.S. would have occurred overseas. The definition of lifecycle greenhouse gas emissions makes it clear that EPA is to determine the aggregate emissions related to the ''full'' fuel lifecycle, including ''all stages of fuel and feedstock production and distribution.'' Thus, EPA could not, as a legal matter, ignore those parts of a fuel lifecycle that occur overseas.

Drawing a distinction between GHG emissions that occur inside the U.S. as compared to emissions that occur outside the U.S. would dramatically alter the lifecycle analysis in a way that bears no apparent relationship to the purpose of this provision. The purpose of including lifecycle GHG thresholds in this statutory provision is to require the use of renewable fuels that achieve reductions in GHG emissions compared to the baseline. Drawing a distinction between domestic and international emissions would ignore a large part of the GHG emission associated with the different fuels, and would result in a GHG analysis of baseline renewable fuels that bears no relationship to the real world emissions impact of the fuels. The baseline would be significantly understated, given the large amount of imported crude used to produce gasoline and diesel, and the importation of finished gasoline and diesel, in 2005. Likewise, the emissions associated with imported renewable fuel would be understated, as it would only consider the emissions from distribution of the fuel to the consumer and the use of the fuel by the consumer, and would ignore both the emissions that occurred overseas as well as the emissions reductions from the intake of CO_2 from growing of the feedstock. While large percentages of GHG emissions would be ignored, this would take place in a context where the global warming impact of emissions is irrespective of

[269] Arguably shifts in acreage between different crops also could be considered a land use change, but we believe there will be less confusion if the term land use change is used with respect to changes in land such as changing from savannah or forest to cropland. There is no difference in result, as in both cases the emissions need to be significant.

where the emissions occur. Thus taking such an approach would essentially undermine the provision, and would be an arbitrary interpretation of the broadly phrased text used by Congress.

While the emissions discussed above would more typically be considered direct emissions related to the full fuel lifecycle, there would also be no basis to cover just foreign direct emissions while excluding foreign indirect emissions. The text of the statute draws no such distinction, nor is there a distinction in achieving the purposes of the provision. GHG emissions impact global warming wherever they occur, and if the purpose is to achieve some reduction in GHG emissions in order to help address global warming, then ignoring GHG emissions because they are emitted outside our borders versus inside our borders interferes with the ability to achieve this objective.

For example, domestic production of a renewable fuel could lead to indirect emissions, whether from land use changes or otherwise, some occurring within the U.S. and some occurring in other countries. Similarly, imported renewable fuel could have resulted in the same indirect emissions whether occurring in the country that produced the biofuel or in other countries. It would be arbitrary to assign the indirect emissions to the domestic renewable fuel but not to assign the identical indirect emissions that occur overseas to an imported product.

Based on the above, EPA believes that the definition of lifecycle greenhouse gas emissions is properly interpreted as including all direct and significant indirect GHG emissions related to the full fuel lifecycle, whether or not they occur in the U.S. This applies to both the baseline lifecycle greenhouse emissions as well as the lifecycle greenhouse gas emissions for various renewable fuels.

EPA recognizes, as discussed later, our estimates of domestic indirect emissions are more certain than our estimate of international indirect emissions. The issue of how to evaluate and weigh the various elements of the lifecycle analysis, and properly account for uncertainty in our estimates, is a different issue, however. The issue here is whether the definition of lifecycle greenhouse gas emissions is properly interpreted as including direct and significant indirect emissions that occur outside the U.S. as well as those that occur inside the U.S.

As to the question of which land use changes should be included in our lifecycle analyses, a central element to focus on is the requirement that such indirect emissions be related to the full fuel lifecycle. The term ''related to'' is generally interpreted as providing a broad and expansive scope for a provision. It has routinely been interpreted as meaning to have a connection to or refer to a matter. To determine whether an indirect emission has the appropriate connection to the full fuel lifecycle, we must look at both the objectives of this provision as well as the nature of the relationship.

In this case, EPA has used a global model that projects a variety of agricultural impacts that stem from the use of feedstocks to produce renewable fuel. We have estimated shifts in types of crops planted and increases in crop acres planted. There is a direct relationship between these shifts in the agricultural market as a consequence of the increased demand for biofuels in the U.S. Increased U.S. demand for biofuel feedstocks diverts these feedstocks from other competing uses, and also increases the price of the feedstock, thus spurring production. To the extent feedstocks like corn and soybeans are traded internationally, this combined impact of lower supply from the U.S. and higher commodity prices encourages international production to fill the gap. Our analysis uses country specific information to determine the amount, location, and type of land use change that would occur to meet this change in production patterns. The linkages are generally close, and are not extended or overly complex. While there is clearly significant uncertainty in determining the specific degree of land use change and the specific impact of those changes, there is considerable overall certainty as to the existence of the land use changes in general, the fact that GHG emissions will result, and the cause and effect linkage of these emissions impacts to the increased use of feedstock for production of renewable fuels.

Overall, EPA is confident that it is appropriate to consider the estimated emissions from land use changes as well as the other indirect emissions as ''related to'' the full fuel lifecycle, based on the reasonable technical basis provided by the modeling for the connection between the full fuel lifecycle and the indirect emissions, as well as for the determination that the emissions are significant. EPA believes uncertainty in the resulting aggregate GHG estimates should be taken into consideration, but that it would be inappropriate to exclude indirect emissions estimates from this analysis. Developing a reasonable estimate of these kinds of indirect emissions will allow for a reasoned evaluation of total GHG impacts, which is needed to promote the objectives of this provision, as compared to ignoring or not accounting for these indirect emissions.

b. System Boundaries

It is important to establish clear system boundaries in this analysis. By determining a common set of system boundaries, different fuel types can then be validly compared. As described in the previous section, we have assessed the direct and indirect GHG impacts in each stage of the full fuel lifecycle for biofuels and petroleum fuels.

To capture the direct emissions impacts of feedstock production in our analysis, we included the agricultural inputs (e.g., the fuel used in the tractor, the energy used to produce and transport fertilizer to the field) needed to grow crops directly used in biofuel production. We also included the N_2O emissions associated with agricultural sector practices used in biofuel production (including direct and indirect N_2O emissions from synthetic fertilizer application, N fixing crops, crop residue, and manure management), as well as the land use change associated with converting land to grow crops directly used in biofuel production. To capture the indirect, or secondary, GHG emissions that result from biofuel feedstock production, we relied on the internationally accepted lifecycle assessment standards developed by the International Organization for Standardization (ISO). Examples of significant secondary impacts include the agricultural inputs associated with crops indirectly impacted by the use of feedstock for biofuel production (domestically and internationally), the emissions associated with land use change that are indirectly impacted by using feedstocks for biofuel production (e.g., to make up for lost U.S. exports), changes in livestock herd numbers that result from higher feed costs, and changes in rice methane emissions indirectly impacted by shifts in acres to produce feedstocks for biofuel production. These indirect or secondary impacts would not have occurred if it were not for the use of biomass to produce a biofuel.

We did not include the infrastructure related GHG emissions (e.g., the energy needed to manufacture the tractor used on the farm) or the facility construction-related emissions (e.g., steel or concrete needed to construct a refinery). As part of the GHG analysis performed for RFS1, we performed a sensitivity analysis on expanding the corn production system to include farm equipment production to determine the impact it has on the overall results of our analysis. We found that including farm equipment production energy use and emissions increases corn ethanol lifecycle energy use and GHG emissions and decreases the corn ethanol lifecycle GHG benefit as compared to petroleum gasoline by approximately 1%. Furthermore, to be consistent in the modeling if system boundaries are expanded to include production of farming equipment they should also be expanded to include producing other material inputs to both the ethanol and petroleum lifecycles. The net effect of this would be a slight increase in both the ethanol and petroleum fuel lifecycle results and a smaller or negligible effect on the comparison of the two.

For this proposal, we have not yet incorporated secondary energy sector impacts, however we plan to have this analysis complete for the final rule. Additional details on the system boundaries are included in the DRIA Chapter 2.

3. Modeling Framework

Currently, no single model can capture all of the complex interactions associated with estimating lifecycle GHG emissions for biofuels, taking into account the ''significant indirect emissions such as significant emissions from land use change'' required by EISA. For example, some analysis tools used in the past focus on process modeling—the energy and resultant emissions associated with the direct production of a fuel at a petroleum refinery or biofuel production facility. But this is only one component in the production of the fuel. Clearly in the case of biofuels, impacts from and on the agricultural sector are important, because this sector produces feedstock for biofuel production. Commercial agricultural operations make many of their decisions based on an economic assessment of profit maximization. Assessment of the interactions throughout the agricultural sector requires an analysis of the commodity markets using economic models. However, existing economy wide general equilibrium economic models are not detailed enough to capture the specific agricultural sector interactions critical to our analysis (e.g., changes in acres by crop type) and would not provide the types of outputs needed for a thorough GHG analysis. As a result, EPA has used different tools that have different strengths for each specific component of the analysis to create a more comprehensive estimate of GHG emissions. Where no direct links between the different models exist, specific components and outputs of each are used and combined to provide an analytical framework and the composite lifecycle assessment results. As this is a new application of these modeling tools, EPA plans to organize peer review of our modeling approach. The individual models are described in the following sections and in more detail in Chapter 2 of the DRIA.

To quantify the emissions factors associated with different steps of the production and use of various fuels (e.g., extraction of petroleum products, transport of feedstocks), we used the spreadsheet analysis tool developed by Argonne National Laboratories, the Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) model. This analysis tool includes the GHG emissions associated with the production and combustion of fossil fuels (diesel fuel, gasoline, natural gas, coal, etc.). These fossil fuels are used both in the production of biofuels, (e.g., diesel fuel used in farm tractors and natural gas used at ethanol plants) and could also be displaced by renewable fuel use in the transportation sector. GREET also estimates the GHG emissions estimates associated with electricity production required for biofuel and petroleum fuel production. For the agricultural sector, we also relied upon GREET to provide GHG emissions associated with the production and transport of agricultural inputs such as fertilizer, herbicides, pesticides, etc. While GREET provides direct GHG emissions estimates associated with the extraction-through-combustion phases of fuel use, it does not capture some of the secondary impacts associated with the fuel, such as changes in the composition of feed used for animal production, which would be expected due to changes in cost. EPA addresses these secondary impacts through other models described later in this section. GREET has been under development for several years and has undergone extensive peer review through multiple updates. Of the available sources of information on lifecycle GHG emissions of fossil energy consumed, we believe that GREET offers the most comprehensive treatment of emissions from the covered sources.

For some steps in the production of biofuels, we used more detailed models to capture some of the dynamic market interactions that result from various policies. Here, we briefly describe the different models incorporated into our analysis to provide specific details for various lifecycle components.

To estimate the changes in the domestic agricultural sector (e.g., changes in crop acres resulting from increased demand for biofuel feedstock or changes in the number of livestock due to higher corn prices) and their associated emissions, we used the FASOM model, developed by Texas A&M University and others. FASOM is a partial equilibrium economic model of the U.S. forest and agricultural sectors. EPA selected the FASOM model for this analysis for several reasons. FASOM is a comprehensive forestry and agricultural sector model that tracks over 2,000 production possibilities for field crops, livestock, and biofuels for private lands in the contiguous United States. It accounts for changes in CO_2, methane, and N_2O from most agricultural activities and tracks carbon sequestration and carbon losses over time. Another advantage of FASOM is that it captures the impacts of all crop production, not just biofuel feedstock. Thus, as compared to some earlier assessments of lifecycle emissions, using FASOM allows us to determine secondary agricultural sector impacts, such as crop shifting and reduced demand due to higher prices. It also captures changes in the livestock market (e.g., smaller herd sizes that result from higher feed costs) and U.S. export changes. FASOM also has been used by EPA to consider U.S. forest and agricultural sector GHG mitigation options.[270]

To estimate the impacts of biofuels feedstock production on international agricultural and livestock production, we used the integrated FAPRI international models, developed by Iowa State University and the University of Missouri. These models capture the biological, technical, and economic relationships among key variables within a particular commodity and across commodities. FAPRI is a worldwide agricultural sector economic model that was run by the Center for Agricultural and Rural Development (CARD) at Iowa State University on behalf of EPA. The FAPRI models have been previously employed to examine the impacts of World Trade Organization proposals and changes in the European Union's Common Agricultural Policy, to analyze farm bill proposals since 1984, and to evaluate the impact of biofuel development in the United States. In addition, the FAPRI models have been used by the USDA Office of Chief Economist, Congress, and the World Bank to examine agricultural impacts from government policy changes, market developments, and land use shifts.

Although FASOM predicts land use and export changes in the U.S. due to

[270] Greenhouse Gas Mitigation Potential in U.S. Forestry and Agriculture, EPA Document 430–R–05–006. *See http://www.epa.gov/sequestration/greenhouse_gas.html.*

greater demand for domestic biofuel feedstock, it does not assess how international agricultural production might respond to these changes in commodity prices and U.S. exports. The FAPRI model does predict how much crop land will change in other countries but does not predict what type of land such as forest or pasture will be affected. We used data analyses provided by Winrock International to estimate what land types will be converted into crop land in each country and the GHG emissions associated with the land conversions. Winrock has used 2001–2004 satellite data to analyze recent land use changes around the world that have resulted from the social, economic, and political forces that drive land use. Winrock has then combined the recent land use change patterns with various estimates of carbon stocks associated with different types of land at the state level. This international land use assessment is an important consideration in our lifecycle GHG assessment and is explained in more detail later in this section.

To test the robustness of the FASOM, FAPRI and Winrock results, we are also evaluating the Global Trade Analysis Project (GTAP) model, a multi-region, multi-sector, computable general equilibrium model that estimates changes in world agricultural production. Maintained through Purdue University, GTAP projects international land use change based on the economics of land conversion, rather than using the historical data approach applied by FAPRI/Winrock. GTAP is designed to project changes in international land use as a result of the change in U.S. biofuel policies, based on the relative land use values of cropland, forest, and pastureland. The GTAP design has the advantage of explicitly modeling the competition between different land types due to a change in policy. As further discussed in Section VI.B.5.iv, GTAP has several disadvantages, some of which prevented its use for the proposal. We expect to correct several of these shortcomings between the proposed and final rules and therefore continue to evaluate how the GTAP model could be used as part of the final rule.

The assessments provided in this proposal use the values provided by the Intergovernmental Panel on Climate Change (IPCC) to estimate the impacts of N_2O emissions from fertilizer application. However, due to concern that this may underestimate N_2O emissions from fertilizer application,[271] we are working with the CENTURY and DAYCENT models, developed by Colorado State University, to update our assessments. The DAYCENT model simulates plant-soil systems and is capable of simulating detailed daily soil water and temperature dynamics and trace gas fluxes (CH_4, N_2O, NO_X and N_2). The CENTURY model is a generalized plant-soil ecosystem model that simulates plant production, soil carbon dynamics, soil nutrient dynamics, and soil water and temperature. We anticipate the results of this new modeling work will be reflected in our assessments for the final rule. More description of this ongoing work is included in the Chapter 2 of the DRIA.

To estimate the GHG emissions associated with renewable fuel production, we used detailed ASPEN-based process models developed by USDA and DOE's National Renewable Energy Laboratory (NREL). While GREET contains estimates for renewable fuel production, these estimates are based on existing technology. We expect biofuel production technology to improve over time, and we projected improvements in process technology over time based on available information. These projections are discussed in DRIA Chapter 4. We then utilized the ASPEN-based process models to assess the impacts of these improvements. We also cross-checked the ASPEN-based process model predictions by comparing them to a number of industry sources and other modeling efforts that estimate potential improvements in ethanol production over time, including the Biofuel Energy Systems Simulator (BESS) model. BESS is a software tool developed by the University of Nebraska that calculates the energy efficiency, greenhouse gas (GHG) emissions, and natural resource requirements of corn-to-ethanol biofuel production systems. We used the GREET model to estimate the GHG emissions associated with current technology as used by petroleum refineries, because we do not expect significant changes in petroleum refinery technology.

We used the EPA-developed Motor Vehicle Emission Simulator (MOVES) to estimate vehicle tailpipe GHG emissions. The MOVES modeling system estimates emissions for on-road and nonroad sources, covers a broad range of pollutants, and allows multiple scale analysis, from fine-scale analysis to national inventory estimation.

Finally, for the FRM we intend to use an EPA version of the Energy Information Administration's National Energy Modeling System (NEMS) to estimate the secondary impacts on the energy market associated with increased renewable fuel production. NEMS is a modeling system that simulates the behavior of energy markets and their interactions with the U.S. economy by explicitly representing the economic decision-making involved in the production, conversion, and consumption of energy products. NEMS can reflect the secondary impacts that greater renewable fuel use may have on the prices and quantities of other sources of energy, and the greenhouse gas emissions associated with these changes in the energy sector. It was not possible to complete this analysis in time for the NPRM

While EPA is using state-of-the-art tools available today for each of the lifecycle components considered, using multiple models necessitates integrating these models and, where possible, applying a common set of assumptions. As discussed later in this section, this is particularly important for the two agricultural sector models, FASOM and FAPRI, which are being used in combination to describe the agricultural sector impacts domestically and internationally. As described in more detail in the DRIA Chapter 5, we have worked with the FAPRI and FASOM models to align key assumptions. As a result, the projected agricultural impacts described in Section IX are relatively consistent across both models. One outstanding issue is the differences between the modeling results associated with increased soybean-based biodiesel production. We intend to further refine the soybean biodiesel scenarios for the final rule. Additional details on all of the models used can be found in DRIA Chapter 2. Finally, as noted earlier, we are planning to have a number of aspects of our modeling framework peer reviewed before finalizing these regulations. In the sections below, we have identified specific peer review plans.

4. Treatment of Uncertainty

While EPA believes the methodology presented here represents a robust and scientifically credible approach, we recognize that some calculations of GHG emissions are relatively straight-forward, while others are not. The direct, domestic emissions are relatively well known. These estimates are based on well-established process models that can relatively accurately capture

[271] Crutzen, P. J., Mosier, A. R., Smith, K. A., and Winiwarter, W.: N_2O release from agro-biofuel production negates global warming reduction by replacing fossil fuels, Atmos. Chem. Phys., 8, 389–395, 2008. *See http://www.atmos-chem-phys.net/8/389/2008/acp-8-389-2008.pdf.*

emissions impacts. For example, the energy and GHG emissions used by a natural gas-fired ethanol plant to produce one gallon of ethanol can be calculated through direct observations, though this will vary somewhat between individual facilities. The indirect domestic emissions are also fairly well understood; however, these results are sensitive to a number of key assumptions (e.g., current and future corn yields). We address uncertainty in this area by testing the impact of changing these assumptions on our results. Finally, the indirect, international emissions are the component of our analysis with the highest level of uncertainty. For example, identifying what type of land is converted internationally and the emissions associated with this land conversion are critical issues that have a large impact on the GHG emissions estimates. We address this uncertainty by using sensitivity analyses to test the robustness of the results based on different assumptions. We also identify areas of additional work that will be completed prior to the final rulemaking. For example, while we utilized an approach using comprehensive agricultural sector models and recent satellite data to determine the emissions resulting from international land use impacts, we are also considering an alternative methodology (the analyses using GTAP) that estimates changes in land use based on the relative land use values of cropland, forest, and pastureland. Additionally, we are considering country-specific information which may allow us to better predict specific trends in land use such as the degree to which marginal or abandoned pasture land will need to be replaced if used instead for crop production. In addition to the sensitivity analysis approach, we will also explore options for more formal uncertainty analyses for the final rule to the extent possible. However, formal uncertainty analyses generally include an assumption of a statistically based distribution of likely outcomes. In the time available for developing this proposal, we have not developed an analytical technique which allows us to determine the likelihood of a range of possible outcome across the wide range of critical factors affecting lifecycle GHG assessment. We specifically ask for recommendations on how best to conduct a sound, statistically based uncertainty analysis for the final rule.

Despite the uncertainty associated with international land use change, we would expect at least some international land use change to occur as demand for crop land increases as a result of this rule. Furthermore, the conversion of crop land will lead to GHG emission from land conversion that must be accounted for in the calculation of lifecycle GHG emissions. As discussed above, we believe that uncertainty in the effects and extent of land use changes is not a sufficient reason for ignoring land use change emissions. Although uncertainties are associated with these estimates, it would be far less scientifically credible to ignore the potentially significant effects of land use change altogether than it is to use the best approach available to assess these known emissions. We anticipate that comment and information received in response to this proposal as well as additional analyses will improve our assessment of land use impacts for the final rule. Finally, we note that further research on key variables will result in a more robust assessment of these impacts in the future.

5. Components of the Lifecycle GHG Emissions Analysis

As described previously, GHG emissions from many stages of the full fuel lifecycle are included within the system boundaries of this analysis. Details on how these emissions were calculated are included in the DRIA Section 2. This section highlights the key questions that we have attempted to address in our analysis. In addition, this section identifies some of the key assumptions that influence the GHG emissions estimates in the following section.

a. Feedstock Production

Our analysis addresses the lifecycle GHG emissions from feedstock production by capturing both the direct and indirect impacts of growing corn, soybeans, and other renewable fuel feedstocks. For both domestic and international agricultural feedstock production, we analyzed four main sources of GHG emissions: agricultural inputs (e.g., fertilizer and energy use), fertilizer N_2O, livestock, and rice methane. (Emissions related to land use change are discussed in the next section).

As described in Section IX.A, EPA uses FASOM to model domestic agricultural sector impacts and uses FAPRI to model international agricultural sector impacts. However, we also recognize that these emission estimates rely on a number of key assumptions, including crop yields, fertilizer application rates, use of distiller grains and other co-products, and fertilizer N_2O emission rates. As described in the following sections, we have used sensitivity analyses to test the impact of changing these assumptions on our results.

i. Domestic Agricultural Sector Impacts

Agricultural Sector Inputs: GHG emissions from agricultural sector inputs (chemical and energy) are determined based on output from FASOM combined with default factors for GHG emissions from GREET. Fuel use emissions from GREET include both the upstream emissions associated with production of the fuel and downstream combustion emissions. Inputs are based on historic rates by region and include projected increases to account for yield improvements over time. This yield increase does not capture changes due to cropping practices such as shifts to corn-after-corn rotations.

N_2O Emissions: FASOM estimates N_2O emissions from fertilizer application and nitrogen fixing crops based on the amount of fertilizer used and different regional factors to represent the percent of nitrogen (N) fertilizer applied that result in N_2O emissions. This approach is consistent with IPCC guidelines for calculating N_2O emissions from the agricultural sector.[272] A recent paper[273] raised the question of whether N_2O emissions are significantly higher than previously estimated. To better understand this issue, we are working with Colorado State University to analyze N_2O emissions. Specifically, Colorado State University will provide several key refinements for a re-analysis of land use and cropping trends and GHG emissions in the FASOM assessment, including:

• Direct N_2O emissions based on DAYCENT simulations with an accounting of all N inputs to agricultural soils, including mineral N fertilizer, organic amendments, symbiotic N fixation, asymbiotic N fixation, crop residue N, and mineralization of soil organic matter. Colorado State University will provide (1) the total emission rate on an acre basis for each simulated bioenergy crop in the 63 FASOM regions and (2) a total emissions for each N source.

• Indirect N_2O emissions on a per acre basis using results from DAYCENT simulations of volatilization, leaching and runoff of N from each bioenergy crop included in the analysis for the 63 FASOM regions, combined with IPCC

[272] 2006 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories, Volume 4, Chapter 11, N_2O emissions from Managed Soils, and C_O2 Emissions from lime and Urea Application. *See http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html.*

[273] Crutzen *et al.,* 2008.

factors for the N_2O emission associated with the simulated N losses.

The analyses with updated N_2O estimates are not yet complete and are not included in this proposal. We expect to complete these analyses for the final rule.

Livestock Emissions: GHG emissions from livestock have two main sources: enteric fermentation and manure management. Enteric fermentation produces methane emissions as part of the normal digestive processes in animals. The FASOM modeling reflects changes in livestock enteric fermentation emissions due to changes in livestock herds. As more corn is used in producing ethanol the price of corn increases, driving changes in livestock production costs and demand. The FASOM model predicts reductions in livestock herds. IPCC factors for different livestock types are applied to herd values to get GHG emissions. The management of livestock manure can produce methane and N_2O emissions. Methane is produced by the anaerobic decomposition of manure. N_2O is produced as part of the nitrogen cycle through the nitrification and denitrification of the organic nitrogen in livestock manure and urine. FASOM calculates these manure management emissions based on IPCC default factors for emissions factors from the different types of livestock and management methods. Manure management emissions are projected to be reduced as a result of lower livestock animal numbers. Use of distiller grains (DGs), as discussed in Section VI.B.5.b, has been shown to decrease methane produced from enteric fermentation if replacing corn as animal feed.[274] This effect is not currently captured in the models but will be considered for the final rule.

Methane from Rice: Most of the world's rice, and all rice in the United States, is grown in flooded fields. When fields are flooded, aerobic decomposition of organic material gradually depletes most of the oxygen present in the soil, causing anaerobic soil conditions. Once the environment becomes anaerobic, methane is produced through anaerobic decomposition of soil organic matter by methanogenic bacteria. FASOM predicts changes in rice acres resulting from the RFS2 program and calculates changes in methane emissions using IPCC factors.

[274] Salil Arora, May Wu, and Michael Wang, ''Update of Distillers Grains Displacement Ratios for Corn Ethanol Life-Cycle Analysis,'' September 2008. *See http://www.transportation.anl.gov/pdfs/AF/527.pdf.*

ii. International Agricultural Sector GHG Impacts

Agricultural Sector Inputs: The FAPRI model does not directly provide an assessment of the GHG impacts of changes in international agricultural practices (e.g., changes in fertilizer load and fuels usage), however it does predict changes in the land area and production by crop type and by country. We therefore determined international fertilizer and energy use based on international data collected by the Food and Agriculture Organization (FAO) of the United Nations and the International Energy Agency (IEA). We used the historical trends based on these FAO and IEA data to project chemical and energy use in 2022. Additional details on the data used are included in DRIA Chapter 2. We intend to review input changes required to increase yields for the final rule and request comment on the extent to which historic trends adequately project what could occur in 2022 or what alternative assumptions should be made and the bases for these assumptions. For example, will changes in farming practices or seed varieties likely result in significantly different impacts on fertilizer use internationally than suggested by recent trends? Additionally, we intend to have the selection and application of this data peer reviewed before the final rule.

N_2O Emissions: For international N_2O emissions from crops, we apply the IPCC emissions factors based on total amount of fertilizer applied and N_2O impacts of crop residue by type of crop produced. As noted above, we are also working with Colorado State University to update these factors as part of the final rule analysis. Additional details on the factors used are included in DRIA Chapter 2.

Livestock Emissions: Similar to domestic livestock impacts associated with an increase in biofuel production, FAPRI model predicts international changes in livestock production due to changes in commodity prices. The GHG impacts of these livestock changes, including enteric fermentation and manure management GHG emissions, were included in our analysis. Unlike FASOM, the FAPRI model does not have GHG emissions built in and therefore livestock GHG impacts were based on activity data provided by the FAPRI model (e.g., number and type of livestock by country) multiplied by IPCC default factors for GHG emissions. We seek comments on the extent to which the use of this methodology is appropriate.

Rice Emissions: To estimate rice emission impacts internationally, we used the FAPRI model to predict changes in international rice production as a result of the increase in biofuels demand in the U.S. Since FAPRI does not have GHG emissions factors built into the model, we applied IPCC default factors by country based on predicted changes in rice acres. We seek comments on this methodology.

b. Land Use Change

We are also addressing GHG emissions associated with land use changes that occur domestically and internationally as a result of the increase in renewable fuels demand in the U.S. Key questions we address in this analysis include the land area converted to crop production, where those acreage changes occur, lands types converted, and the GHG emission impacts associated with different types of land conversion.

EPA recognizes that analyzing international impacts of land use change can introduce additional uncertainty to the GHG emissions estimates. At this time, we do not have the same quality of data for international crop production and projected future trends as we do for the United States. For example, prediction of the economic and geographic development of developing country agricultural systems is far more difficult than prediction of future U.S. agricultural development. The U.S. has a very mature agriculture system in which the high quality agricultural lands are already under production and the infrastructure to move crops to market is already in place. This is not necessarily the case in other countries. Some very large countries expected to play a significant role in future agricultural production are still developing their agricultural system. Brazil, for example, has vast areas of land that may be suitable for commercial agricultural production that would allow for significant expansion in crop lands. One of the restraints on expansion is the relative lack of infrastructure (e.g., road and rail systems) that would allow shipment of expanded crop production to market. Identifying what type of land is converted internationally and the emissions associated with this land conversion can significantly affect our assessment of GHG impacts. We present a range of results for differences in these and other assumptions in Section VI.C.2, and we seek comment on our approach so that the final rule will use the best science to provide credible estimates of lifecycle GHG emissions for each biofuel.

i. Amount of Land Converted

The main question regarding the amount of new land needed to meet an increasing demand for biofuels hinges on assumptions about the intensification of existing production versus expansion of production to other lands. This interaction is driven by the relative costs and returns associated with each option, but there are other factors as described below.

Co-Products: One factor determining the amount of new crop acres required under an increased biofuel scenario is the treatment of co-products. For example, distillers grains (DGs) are the major co-product of dry mill ethanol production that is also used as animal feed. Therefore, using the DGs as an animal feed to replace the use of corn tends to offset the loss of corn to ethanol production, and reduces the need to grow additional corn to feed animals. As the renewable fuels industry expands, the handling and use of co-products is also expanding. Some uncertainty is associated with how these co-products will be used in the future (e.g., whether it can be reformulated for higher incorporation into pork and poultry diets, whether it will be dried and shipped long distances, whether fractionation will become widespread).

Both our FASOM and FAPRI models account for the use of DGs in the agricultural sector. The FASOM and FAPRI models both assume that a pound of co-product would displace roughly a pound of feed. However, a recent paper by Argonne National Laboratory [275] estimates that 1 pound of DGs can displace more than a pound of feed due to the higher nutritional value of DGs compared to corn.

The Argonne replacement ratios do not take into account the dynamic least cost feed decisions faced by livestock producers. The actual use of DGs will depend on the maximum inclusion rates for each type of animal (based on the digestibility of DGs), the displacement ratio for each type of animal (based on DGs energy and protein content), and the adoption rate (based on the feed value relative to price). Furthermore, as world vegetable oil prices increase, dry mill ethanol producers will have an incentive to extract the corn oil from the DGs. This step changes the nutritional content of the DGs, which results in different replacement rates than the ones currently used in FASOM or described by Argonne. As we plan to evaluate and incorporate a least cost feed rationing approach for the final rule, we invite comment on the expected future uses of DGs and their displacement ratios.

Crop Yields: Assumptions about yields and how they may change over time can also influence land use change predictions. Domestic yields were based on USDA projections, extrapolated out to 2022. In 2022, we estimate that the U.S. average corn yield will be approximately 180 bushels/acre (a 1.6% annual increase consistent with recent trends) and average U.S. soybean yields will be approximately 50 bushels per acre (a 0.4% annual increase).[276] Using the FASOM model, we conducted a sensitivity analysis on the impact of higher and lower yields in the U.S. Details on this scenario are included in DRIA Chapter 5.1. International yields changes are also based on the historic trends. The FAPRI model contains projected yields and yield growths that are generally lower in other countries compared to the U.S. We request comment on the projected increase in crop yields in the U.S (including consideration of how emerging seed types might be expected to increase average crop yields). We also request comment on the use of historical trends to predict future agricultural production in other countries and request information on alternative methodologies and supporting data that would allow us to base our predictions on alternative assumptions.

The FASOM and FAPRI models currently do not take into account changes in productivity as crop production shifts to marginal acres or the impact of price induced yield changes on land use change. We would expect these two factors could work in opposite directions and therefore could tend to offset each other's impacts. Marginal acres in fully developed agricultural systems are expected to have lower yields, because most productive acres are already under cultivation. This may not be the case in developing systems where prime agricultural lands are not currently in full production due to, for example, lack of supporting infrastructure. Changes in agricultural inputs (e.g., fertilizer, pesticides) can also change crop yield per acre. Higher commodity prices might provide an incentive to increase production in existing acres. If the costs of increasing productivity on existing land were minimal relative to the value of the increased production, then agricultural landowners would presumably adopt these productivity-enhancing actions under the reference case. Although it is reasonable to assume a trend wherein some productivity-enhancing practices may become profitable if commodity prices are high enough such as might occur as the result of increased biofuel production, it is not clear that farmers would find significant increases in production per acre profitable. If crop yields either domestically or international are significantly impacted by higher commodity prices driven by general increase in worldwide demand, this could affect our assessment of land use impacts and the resulting GHG emissions due to increased biofuel demand in the U.S. However, as described in Section IX, the change in commodity prices associated with the increase in U.S. biofuel as a result of the EISA mandates are very small and perhaps not large enough to induce significant increased yield changes. We invite comment on projected yields and the potential impact of increased use of marginal lands and price induced yield changes. For the final rule we plan to explicitly model the impact of price induced yield changes.

Land Conversion Costs: The assumed cost associated with different types of land conversion can also play a key role in determining how much land will be converted. In FASOM, the decision to convert land from pasture or forest to cropland is based on whether the landowner can increase the net present value of expected returns through conversion (including any costs of conversion). Among other things, the decision to convert land depends on regional yields, costs, and other factors affecting profitability and on the returns to alternative land uses. In other words, FASOM assumes that land conversion is based on maximizing profits rather than minimizing costs. Additional details on land conversions costs incorporated in FASOM are included in DRIA Chapter 2.

FAPRI does not explicitly model land conversion costs, however the international production supply curves used by the FAPRI model implicitly take into account conversion costs. FAPRI's supply curves are based on historical responses to price changes, which take into account the conversion costs of land, based on expected future returns associated with land conversion. Thus, we believe that our assessments of international land use changes are based on economic land-use decisions.

ii. Where Land is Converted

The first step in determining what domestic and international land will be converted due to biofuels production is to estimate the extent to which the increased demand for biofuel feedstock

[275] Salil *et al.*, 2008.

[276] Note that these same assumptions apply in both the reference case and the control cases.

will be met through increased U.S. agriculture production or reductions in U.S. exports.

This question has several implications. For example, U.S. agriculture production is typically more energy and input intensive but has higher yields than agricultural production in other parts of the world. This implies that increased production in the U.S. has higher input GHG emission impacts but lower land use change impacts compared to overseas production. In addition, the types of land where agriculture would expand would be different in the U.S. vs. other parts of the world.

EPA's analysis relies on FASOM predictions to represent changes in the U.S. agricultural sector, including land use, and on FAPRI to predict the resulting international agricultural sector impacts including the amount of additional cropland needed under different scenarios. The impact on the international agricultural sector is highly dependent on the U.S. export assumptions. As the FASOM model was used to represent domestic agricultural sector impacts with an assumed export picture, the international agricultural sector impacts from FAPRI needed to be based on a consistent set of export assumptions. We worked with FASOM and FAPRI modelers to ensure this consistency. This involved coordinating crop yields, ethanol yields and co-product use, assumptions regarding CRP acres, a consistent export response, and a consistent livestock demand and feed use in both models.

As shown in Chapter 2 of the DRIA, coordination of assumptions has generated a consistent export picture response from both the FASOM and FAPRI model for the majority of biofuel and feedstock scenarios considered. Differences in responses in the biodiesel scenario remain between the two models. FASOM assumes more biodiesel will come from new soybean acres (but total domestic acres are relatively constant as reductions in other crops offset the increase in soybean acres). In comparison, FAPRI contains more types of oil seed crops and has a more elastic demand in the soybean oil market. The FAPRI model also allows for some corn oil fractionation from DGs, which can be used as a substitute for soybean oil. The FASOM model predicts a larger change in net exports than the FAPRI model. Since we are using the FAPRI model as the basis for estimating international land use changes, we may be underestimating the international land use change emissions associated with soybean based biodiesel. For the final rule, EPA will work, in particular, to resolve the differences in soybean production impact between the models. This, too, may modify our assessment of the biodiesel lifecycle GHG emissions.

Due to the wide range of carbon and biomass properties associated with land in different parts of the world, the location of crop conversion is also important to our lifecycle analysis. For example, an average acre of forest in Southeast Asia stores a much larger quantity of carbon than a typical acre of forest in Northern Europe. The FAPRI model provides estimates of the acreage change by country and crop that result from a decrease in U.S. exports due to the increase in U.S. biofuel demand. These estimates are based on historic responsiveness to changes in prices in other countries. Implicit in these supply curves are the costs associated with converting new land to crop production and the relative competitiveness of each country to increase production based on production costs, yields, transportation costs, and currency fluctuations. FAPRI also includes in its baseline projections of future population growth, GDP growth, and other macroeconomic changes. FAPRI also takes into account the fact that not all U.S. exports will need to be made up in international production, as there is a small decreases in demand due to shifts in crop production and higher prices.

iii. What Type of Land is Converted

In the same way that the location of land conversion is important, the type of land that is converted is critical to the magnitude of impact on the GHG emissions associated with biofuel production. For example, the conversion of rainforest results in a much larger increase in GHG emissions than the conversion of grassland. There are several options for determining what type of land will be converted to crop acreage. One option is to model land rental rates for different types of land (e.g., forest, pasture, and crop production), and allow the model to choose the type of land that is expected to have the highest net returns. This approach is used by FASOM on the domestic side. Another option is to use historical land conversion trends in a given country or region. The FAPRI/Winrock approach uses this approach for international land use conversion.

Domestic: The FASOM model includes competition between land types, agriculture, pasture, and forest land. The interaction is based on providing the highest rate of return across the different land types. Therefore domestically we have the ability to explicitly model what types of land would be converted to increased agriculture based on the rates of return for different land types for the 63 regions in FASOM. For this draft proposal we incorporated the agricultural component (which includes both existing cropland and pasture) of the FASOM model, but not the forestry component (see Section IX.A for explanation). Therefore, this analysis assumes that all additional cropland predicted by FASOM comes from pasture. As we incorporate the forestry component for the final rule analysis we would expect to see more interaction between the forestry and agriculture sector such that there may be conversion of forest to agriculture based on additional cropland needed. While we do not know if forest will be converted to cropland or the extent that this might occur, if domestic forests were converted to cropland, we would expect domestic GHG emissions would increase. This work will be incorporated for our final rule.

International: Basing land use change on the economics and rates of return of different land uses offers advantages for capturing potential future land use changes. However, the only model potentially capable of fully incorporating this calculation internationally, GTAP, is still in the process of being updated and modified for this purpose. Thus, EPA has chosen to use historical patterns as identified by satellite images to estimate future land conversion. This approach is referred to here as the FAPRI/Winrock approach because it relies on the integration of each of these tools.

EPA believes that FAPRI/Winrock is a scientifically credible modeling approach at this time. However, we will continue to work with the GTAP model to help test the results generated by our primary approach.

FAPRI/Winrock

Since FAPRI does not contain information on what type of land is being converted into cropland, we worked with Winrock International, a global nonprofit organization, to address this question. A key advantage of Winrock is that they can accurately measure and monitor trends in forest and land use change, forest carbon content, biodiversity, and the impact of infrastructure development. Furthermore, several of the Winrock staff were involved in the development of the IPCC land use change good practice guidance and are widely recognized as the leaders in this field.

Using satellite data from 2001–2004, Winrock provided a breakdown of the types of land that have been converted into cropland for a number of key agriculturally producing countries based on the International Geosphere-Biosphere Programme (IGBP).[277] The IGBP land cover list includes eleven classes of natural vegetation, three classes of developed and mosaic lands, and three classes of non-vegetated lands. The natural vegetation units distinguish evergreen and deciduous, broadleaf and needle-leaf forests, mixed forests, where mixtures occur; closed shrublands and open shrublands; savannas and woody savannas; grasslands; and permanent wetlands of large areal extent. The three classes of developed and mosaic lands distinguish among croplands, urban and built-up lands, and cropland/natural vegetation mosaics. Classes of non-vegetated land cover units include snow and ice; barren land; and water bodies. Winrock aggregated these categories into five similar classes: five classes of forest were combined into one, two classes of savanna were combined into one, and two classes of shrubland were combined into one. The final land cover categories for this analysis are forest, cropland, grassland, savanna, and shrubland. The rest of the IGBP categories not of interest to this analysis were reclassified into the background. The satellite data represents different types of land cover, which we are using as a proxy for land use.

A key strength of this approach is that satellite information is based on empirical data instead of modeled predictions. Furthermore, it is reasonable to assume that recent land use changes have been driven largely by economics and recent historical patterns will continue in the future absent major economic or land use regime shifts caused, for example, by changes in government policies. We are using the FAPRI model to predict where in the world, based on economic conditions, the most likely increase in agriculture production will occur as a result of the EISA mandates. We are then using the historical satellite data to address the key question: If additional land is needed for crop production in a particular country, what type of land will be used? The Winrock analysis addresses this question by calculating the weighted average type of land that was converted to cropland between 2001 and 2004. Essentially, we are using the Winrock data to determine the type of land that is most likely to be converted to cropland, should additional acres be needed as predicted by FAPRI.

Table VI.B.5–1 shows the percentage of land converted to cropland between 2001 and 2004 according to the Winrock satellite data analysis for the countries currently available. We use these percentages to calculate a weighted average of the types of land converted into cropland. For example, if FAPRI predicts that one additional acre of cropland will be brought into production in Argentina, we used the Winrock data to estimate that 8% on average of that acre will come from forest, 40% of that acre will come from grassland, 45% of that land will come from savanna, and 8% of that land will come from shrubland. Using GTAP might result in different percentage weights.

TABLE VI.B.5–1—TYPES OF LAND CONVERTED TO CROPLAND BY COUNTRY

[In percent]

Country	Forest	Grassland	Savanna	Shrub
Argentina	8	40	45	8
Brazil	4	18	74	4
China	17	38	23	21
EU	27	16	36	21
India	7	7	33	53
Indonesia	34	5	58	4
Malaysia	74	3	19	3
Nigeria	4	56	36	4
Philippines	49	5	44	3
South Africa	10	22	53	15

Source: Winrock Satellite Data (2001–2004).

We are assuming that the weighted average, resulting from agriculture demand as well as other possible drivers, is a reasonable estimate of the land use change attributable to increased agricultural demand. A shortcoming of this approach is that it assumes that when new crop acres are needed to meet increased agricultural demand these crop acres will follow the average pattern of recent historical land conversion, recognizing that this pattern is based on a variety of drivers of land use change, not all of which are associated with agricultural demand. This approach is not able to isolate from the historical pattern the land use changes stemming just from increased agricultural demand. For example, it is likely that in some cases trees are being removed from forests for the value of the wood. However, having removed valuable wood, additional clearing may occur to allow the land to be used for pasture or cropland. In that case the GHG emissions associated with the removal of the trees would not occur as a consequence of increased agricultural demand, but as a consequence of increased demand for the wood, while the GHG emissions associated with the additional clearing would occur as a consequence of the agricultural demand.

As a result, the Winrock data also does not distinguish between the land-use impacts associated with one crop versus another. Indeed, at least in the case of sugarcane production in Brazil, a number of researchers argue that expanded sugarcane production is likely to occur in significant part through the use of degraded or abandoned pasture land without additional land use impact.[278] These research reports suggest that general historical trends in land use change to grow crops in Brazil may not pertain to expected growth in sugarcane production. Ideally, an analysis of a U.S. biofuels policy's influence on land use change would

[277] U.S. Geological Survey MODIS Data Set Documentation. *See http://edcdaac.usgs.gov/modis/mod12q1v4.asp.*

[278] *See* for example ''Mitigation of GHG emissions using sugarcane bio-ethanol—Working Paper'' by Isaias C. Macedo and Joaquim E. A. Seabra, and ''Prospects of the Sugarcane Expansion in Brazil: Impacts on Direct and Indirect Land Use Changes—Working Paper'' by Andre Nassar *et al.*, both received by EPA October 13, 2008.

model the marginal impact that U.S. biofuel would have on land use and land use change in addition to baseline land use change. Use of historic land use change data is capturing some of this baseline land use change. Comments are requested on our approach of assuming historical land use changes will continue to be followed in response to increased agricultural demand associated with our biofuel policy. We also invite comment on what alternative methodologies and data are available, if any, to better link the impacts of biofuels to land use change. To the extent additional information or data may be available for certain countries such as the example of Brazil, we also ask how this country-specific data and similar information might best be integrated with the modeling results otherwise available. Furthermore, to the extent different government policies can shift land use patterns (e.g., through regulations, financial supports), these weighted averages could change in the future. We request comment on whether these government policies and regulations should be incorporated into the future land use change calculations and the best methodology for taking into account these changes.

The Winrock data and analyses present an aggregate picture of land use changes; they cannot predict the nature of the land use change that will result due to an additional acre of corn planted in a country versus an additional acre of sugarcane or soybeans. In reality, sugarcane may be more suitable for planting in different regions with different soil types compared to corn or soybeans. However, because we are using weighted averages to characterize the type of land that is converted to crop acres, all additional crop acres in a particular country are treated identically.

Winrock also provides information on land conversions between other categories (e.g., forest to savanna). For one set of GHG analyses, we assumed that land taken out of actively managed use [279] (e.g., pasture used for livestock production) would have to be replaced with new pasture acreage, thereby capturing some of the domino effect associated with converting previously productive land into cropland. Therefore, in addition to land conversion shown in Table VI.B.5–1, we also include land conversion to replace some of the grassland and savanna that is used as pasture. An alternative approach would be to assume that no additional land is necessary, since there is a significant amount of pastureland that could be used more intensively for grazing purposes. For example, as noted above, in Brazil almost all of the direct land conversion associated with expanding sugarcane production is coming out of existing pasture land, in some cases, depleted, low value pasture land, that may have relatively low levels of stored carbon compared to other land. Also in Brazil there is a trend toward more intensive use of existing pasture land by grazing higher numbers of cattle per unit of pasture, decreasing the need to replace pasture converted to cropland. This more intensive use of pasture is encouraged by two factors: improved grasses which can sustain more intensive grazing and lack of transportation infrastructure which tends to constrain geographic expansion of pasture lands. However, we also note that depleted cropland in Brazil might also be suitable for other crop production. To extend sugarcane limits to production of these other crops on this land, the indirect effect could be that these crops move into other areas of Brazil and resulting in increased emissions due to land use change. We invite comment on alternative methodologies for predicting land use changes in particular in other countries. Some alternative methodologies are described in more detail in Chapter 2 of the DRIA.

The FAPRI model results have been used in peer reviewed literature in conjunction with satellite data to assess land use changes [280] and we also believe it is an appropriate method for projecting biofuel induced land use changes. However, we recognize the uncertainty associated with this approach and, in addition to seeking public comment, we plan to conduct an expert peer review of the data and methods used, including the appropriateness of using historic satellite data to project future land use changes.

iv. What Are the GHG Emissions Associated With Different Types of Land Conversion?

Our estimates of domestic land use change GHG emissions are based on outputs of the FASOM model. As we are just using the agricultural portion of the FASOM model for this analysis the land use change GHG emissions are limited to changes in land use for existing crop and pasture land. Some of that crop land could currently be fallow and some of the pasture land could currently be unused. However, no new crop or pasture land (beyond some Conservation Reserve Program (CRP) land due to legislative changes in the program) is added compared to current levels. Thus FASOM only models shifts in the use of this land.

Changes in the agricultural sector due to increased corn used for ethanol have impacts on land use change in a number of ways. FASOM explicitly models change in soil carbon from increased crop production acres and from different types of crop production. FASOM also models changes in soil carbon from converting non crop land into crop production. Land converted to crop land could include pasture land. As recommended by USDA, we are assuming that 32 million acres of CRP land will remain in that program even if crop prices increase and thus increase land values. This assumption is consistent with the 2008 Farm Bill, which limits CRP acres to 32 million. A sensitivity analysis on this assumption is included in Chapter 5 of the DRIA.

For the international impacts, we used the 2006 IPCC Agriculture, Forestry, and Other Land Use (AFOLU) Guidelines [281] and the Winrock provided GHG emissions factors for each country based on the weighted average type of land converted. GHG emissions estimates were based on immediate releases (e.g., changes in biomass carbon stocks, soil carbon stocks, and non-CO_2 emissions assuming the land is cleared with fire) and foregone forest sequestration (the future growth in vegetation and soil carbon). Additional details on these calculations are included in Chapter 2 of the DRIA. For the emissions factors presented, we assume forests cleared would have continued to sequester carbon for another 80 years, based on the amount of time it takes for forests to reach a general equilibrium stage. We request comment on whether it is appropriate to include foregone sequestration in the GHG emissions estimates. Carbon soil calculations [282] take into account the annual changes in carbon content in the top 30 centimeters of soil over the first 20 years, based on IPCC recommendations.[283] We also request comment on whether soil carbon calculations should be based on the top 30 centimeters of soil. These emission factors do not include credits for harvested wood products, based on the expectation that they would have a

[279] GTAP Land Cover Data (2000–2001).

[280] Searchinger *et al.,* 2008.

[281] 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 4, Agriculture, Forestry and Other Land Use (AFOLU). *See http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html.*

[282] *See ftp://www.daac.ornl.gov/data/global_soil/IsricWiseGrids.*

[283] 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 4, Section 5.3.3.4.

very small impact on our estimates of land use change emissions. However, we intend to analyze the impact of wood product credits for the final rule. We invite comment on whether it is appropriate to include wood product credits in the GHG emissions estimates.

GHG emissions associated with land use changes vary significantly based on the type of land and the geographic region. For example, the GHG emissions associated with converting an acre of grassland to cropland in China are lower than the emissions associated with converting an acre of shrubland to cropland in China. Similarly, the GHG emissions associated with converting an acre of forest to cropland in Malaysia are larger than the emissions associated with converting an acre of forest in Nigeria to cropland. Where country specific emission factors were not available in time for the proposal, we used world average. For the proposal, we focused on the countries with the largest projected changes in crop acreage. The Winrock data currently covers 63% of total land use change acres associated with corn ethanol, 53% of the acres associated with biodiesel, 57% of the acres associated with switchgrass, and 87% of the acres associated sugarcane ethanol. We will continue to add additional countries for our analysis for the final rule. Two changes that may impact these results for the final rule include the addition of perennial crops and the conversion on land with peat soils. We request comment on our calculation of emission factors due to land use change; improved data and assumptions are specifically requested. Additionally, we plan to have the calculation of these emissions factors reviewed by experts in this field. Details on the Winrock estimates are included in the DRIA Chapter 2.

GTAP Approach:

GTAP is an economy-wide general equilibrium model that was originally developed for addressing agricultural trade issues among countries. The databases and versions of the model are widely used internationally.[284] Since its inception in 1993, GTAP has rapidly become a common ''language'' for many of those conducting global economic analysis. For example, the WTO and the World Bank co-sponsored two conferences on the so-called Millennium Round of Multilateral Trade talks in Geneva. Here, virtually all of the quantitative, global economic analyses were based on the GTAP framework. Over the past few years, a version of the model was developed to explicitly model global competition among different land types (e.g., forest, agricultural land, pasture) and different qualities of land based on the relative value of the alternative land-uses. More recently, it was modified to include biofuel substitutes for gasoline and diesel. In simulating land use changes due to biofuels production, GTAP explicitly models land-use conversion decisions, as well as land management intensification. For example, it allows for price-induced yield changes (e.g., farmers can reallocate inputs to increase yields when commodity prices are high) and considers the marginal productivity of additional land (e.g., expansion of crop land onto lower quality land as a result of the increased use of biofuels). Most importantly, in contrast to other models, GTAP is designed with the framework of predicting the amount and types of land needed in a region to meet demands for both food and fuel production. The GTAP framework also allows predictions to be made about the types of land available in the region to meet the needed demands, since it explicitly represents different land types within the model.

The global modeling of land-use competition and land management decisions is relatively new, and evolving.[285] GTAP does not yet contain cellulosic feedstocks in the model. In addition, GTAP does not currently contain unmanaged land, which could be a major factor driving current GTAP land use projections and is a significant potential source of GHG emissions. We expect to update GTAP with cellulosic feedstocks and unmanaged land in time for the final rule.

Our proposal is therefore based on the FAPRI/Winrock estimates. There are advantages and disadvantages associated with any model choice and we have chosen the FAPRI/Winrock combination as the best approach available for preparing the proposal. Although we have not relied on the current version of GTAP for the principal analyses in this proposal, others have used versions of the current model to assess land use changes which could result from expanded biofuel demand. The California Air Resources Board as part of the analysis for their low carbon fuel standard used GTAP to model indirect land use change for biofuels. More information on their program and GTAP analysis can be found at *http://www.arb.ca.gov/fuels/lcfs/lcfs.htm*. Furthermore, researchers from Purdue University have released a report on work using GTAP to look at land use change associated with corn ethanol production scenarios.[286] This work was partially funded by Argonne National Lab for possible inclusion in the GREET model. We anticipate additional refinements will be made to the GTAP model between the proposal and final rule and we will include this information and results in the docket as they become available. We invite comments in this NPRM on the use of the GTAP model in helping to establish the GHG emissions estimates for the final rule.

v. Assessing GHG Emissions Impacts Over Time and Potential Application of a GHG Discount Rate

When comparing the lifecycle GHG emissions associated with biofuels to those associated with gasoline or diesel emissions, it is critical to take into consideration the time profile associated with each fuel's GHG emissions stream. With gasoline, a majority of the lifecycle GHG emissions associated with extraction, conversion, and combustion are likely to be released over a short period of time (i.e., annually) as crude oil is converted into gasoline or diesel fuel which quickly pass to market. This means that the lifecycle GHG emissions of a gallon of gasoline produced one year are unlikely to vary much from the lifecycle GHG emissions of a similar gallon of gasoline produced in a subsequent year.

In contrast, the lifecycle GHG emissions from the production of a typical biofuel may continue to occur over a long period of time. As with petroleum based fuels, renewable fuel lifecycle GHG emissions are associated with the conversion and combustion of biofuels in every year they are produced. In addition, GHG emissions could be released through time if new acres are needed to produce corn, soybeans or other crops as a replacement for crops that are directly used for biofuel production or displaced due to biofuels production. The GHG emissions associated with converting land into crop production would accumulate over time with the largest release occurring in the first few years due to clearing with fire or biomass decay. After the land is converted, moderate amounts of soil carbon would continue to be released for

[284] *https://www.gtap.agecon.purdue.edu.*

[285] *See* Hertel, Thomas, Steven Rose, Richard Tol (eds.), (in press). *Economic Analysis of Land Use in Global Climate Change Policy,* Routledge Publishing.

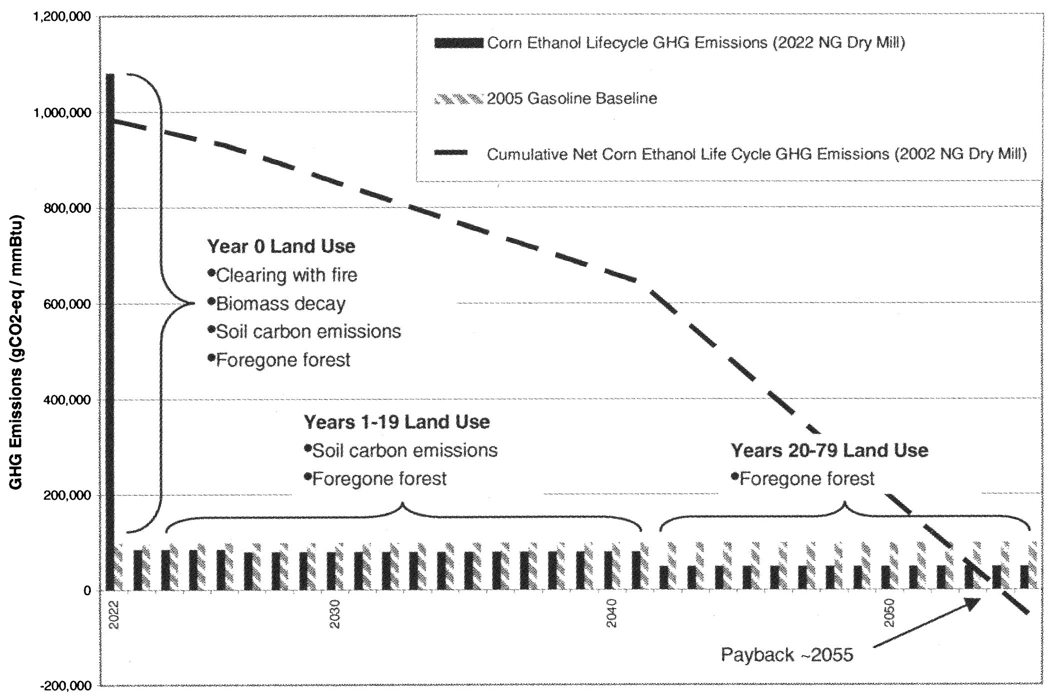
[286] *Land Use Change Carbon Emissions due to US Ethanol Production,* Wallace E. Tyner, Farzad Taheripour, Uris Baldos, January 2009. Available at *http://www.agecon.purdue.edu/papers/biofuels/Argonne-GTAP_Revision%204a.pdf.*

approximately 20 years.[287] Furthermore, there would be foregone sequestration associated with forest clearing as this forest would have continued to sequester carbon had it not been cleared for approximately 80 years.

Therefore, we have included an analysis which considers GHG emissions from land use change that may continue for up to 80 years, based on our estimate of the average length of foregone sequestration after a forest is cleared. Annual foregone sequestration rates were estimated by ecological region using growth rates for forests greater then 20 years old from the 2006 IPCC guidelines for Agriculture, Forestry and Other Land Use.[288] Studies have estimated that new forests grow for 90 years to over 120 years.[289] More recent estimates suggest that old growth forests accumulate carbon for up to 800 years.[290] The foregone sequestration methods used in this proposal are within the range supported by the scientific literature and the 2006 IPCC guidelines. Details of the foregone sequestration estimates are included in DRIA Chapter 2. We seek comment on our estimate of the average length of annual foregone forest sequestration for consideration in biofuel lifecycle GHG analysis.

Figure VI.B.5–1 shows how lifecycle GHG emissions vary over time for a natural gas fired dry mill corn ethanol plant assuming that all land use change occurs in 2022. While biomass feedstocks grown each year on new cropland can be converted to biofuels that offer an annual GHG benefit relative to the petroleum product they replace, these benefits may be small compared to the upfront release of GHG emissions from land use change. Depending on the specific biofuel in question, it can take many years for the benefits of the biofuel to make up for the large initial releases of carbon that result from land conversion (e.g., the payback period). As shown in Figure VI.B.5–1, the payback period for a natural gas-fired dry mill corn ethanol plant which begins operation in 2022 would be approximately 33 years. We present a similar payback period calculation for the full range of biofuels analyzed in Section VI.C.

Figure VI.B.5-1
Corn Ethanol Lifecycle GHG Emissions over Time and Payback Period



As required by EISA, our analysis must demonstrate whether biofuels reduce GHG emissions by the required percentage relative to the 2005 petroleum baseline. A payback period alone cannot answer that question. Since the payback period alone is not sufficient for our analysis, we have considered accounting methods for capturing the full stream of emissions and benefits over time. There are at least two necessary criteria for the accounting methods we have considered. First, they must provide an estimate of renewable fuel lifecycle GHG emissions that is consistent over time. Otherwise, for example, all of the upfront emissions due to land clearing would be assigned to corn ethanol produced in the first year, and none of those emissions to corn ethanol produced the following years even though this land use change is central to the production over these following years. Second, the accounting method must also provide a common metric that allows for a direct comparison of biofuels to gasoline or

[287] Following Section 5.3.3.4 of the IPCC AFOLU guidelines, the total difference in soil carbon stocks before and after conversion was averaged over 20 years.

[288] Table 4.9 from the 2006 GL AFOLU was used to estimate the lost C sequestration of forests that were converted to another land use.

[289] *See* Greenhouse Gas Mitigation Potential in U.S. Forestry and Agriculture, EPA Document 430–R–05–006 for a discussion of the time required for forests to reach carbon saturation.

[290] Luyassert, S *et al.*, 2008. Old-growth forests as global carbon sinks. *Nature* 455: 213–215. Link: *http://www.nature.com/nature/journal/v455/n7210/abs/nature07276.html.*

diesel. When accounting for the time profile of lifecycle GHG emissions, the two most important assumptions in the determination of whether a biofuel meets the specified emissions reduction thresholds include: (1) The time period considered and (2) the discount rate (which could be zero) applied to future emissions streams.

Time Periods Considered

The illustration of the payback period in Figure VI.B.5–1 demonstrates the importance of the time period over which to consider both the lifecycle GHG emissions increases associated with the production of a biofuel as well as the benefits from using the biofuel. As mentioned above, based on our lifecycle GHG analysis for this proposed rule we estimate that the payback period for corn ethanol produced in a natural gas-fired dry mill is approximately 33 years. In this case, if we measure GHG impacts over a time period of less than 33 years we will determine that the total corn ethanol produced over this time period increases lifecycle GHG emissions. Conversely, total corn ethanol production will reduce net lifecycle GHG emissions if we look beyond 33 years, with net emissions reductions increasing the further into the future we extend our analysis. To inform our decision of which time period for analysis is most appropriate, we must consider a number of factors including but not limited to the length of time over which we expect a particular biofuel to be produced, the time over which biofuel production continues to impact GHG emissions into the future, the importance of achieving near-term GHG emissions reductions, and the increasing uncertainty of projecting GHG emissions impacts into the future. Based on these considerations, our discussion of lifecycle analyses prepared for this proposed rule focuses on time periods of 100 years and 30 years.

There are advantages and disadvantages to using the 100 and 30 year time frames to represent both emissions impacts as well as emissions benefits of use of biofuels over time. There are several principal reasons for using the 100 year time frame. First, greenhouse gases are chemically stable compounds and persist in the atmosphere over long time scales that span two or more generations. Second, the 100 year time frame captures the emissions associated with land use change that may continue for a long period of time after biofuel-induced land conversion first takes place.[291] For example, physical changes in carbon stocks on unmanaged lands may not slow until after 100 years, and optimal forest rotation ages can influence greenhouse gas emissions for 100 years on managed lands. Similarly, a 100 year time frame would allow estimating the future changes in the land should the need for these changes due to biofuel production cease. For example, as discussed in more detail below, if production of a biofuel ended, then the land use impacts associated with that biofuel would also tend to go away in a process known as land use reversion. A longer time frame would allow assessment of the impacts of that land use reversion.

For a number of reasons we believe that biofuel production could continue for a long time into the future. As biofuel technologies advance and production costs are decreased, it is likely that renewable fuels will become increasingly competitive with petroleum-based fuels. Another reason for expecting long term biofuel production is that, unlike a specific facility that has an expected lifetime, the RFS program does not have a specified expiration date. The expectation that renewable fuel production will continue for a long time provides justification for using a longer time frame for analysis, such as 100 years. Another reason for considering an inter-generational time period such as 100 years for lifecycle GHG analysis is that climate change is a long-term environmental problem that may require GHG emissions reductions for many decades.

The 100 year time frame also has drawbacks. A general concern with projecting impacts over a very long time period is that uncertainty increases the further the analysis is extended into the future. For example, a 100 year analysis presumes that production of a particular biofuel will continue for at least 100 years. Although we expect renewable fuel production as a whole to continue for a long time, it is possible that due to changing market conditions or other factors, the use of first generation biofuels (e.g., corn ethanol) could see a decline in use over a shorter period of time.

For this proposal, we are also showing the results of analyzing both GHG emissions impacts of producing a biofuel as well as benefits from using the biofuel over 30 years, a time frame which has been used in the literature to estimate the greenhouse gas impacts of biofuels.[292] [293] Since a time period such as 30 years would truncate the potential GHG benefits that accumulate over time, this second option would reduce the GHG benefits of biofuels relative to gasoline or diesel compared to assuming a longer time frame for biofuel production such as 100 years.

One advantage of using a shorter time period is that it is more ''conservative'' from a climate change policy perspective. In general, the further out into the future an analysis projects, the more uncertainty is introduced into the results. For example, with a longer time period for analysis, it is more likely that significant changes in market factors or policies will change the incentives for producing biofuels. If a biofuel only has greenhouse benefits when considered in an extended future time frame, it is not clear that these benefits will be realized due to the inherent uncertainty of the future. Also, potential irreversible climate change impacts or future actions in other sectors of the economy, such as reductions from stationary sources, could influence the relative importance of renewable fuel GHG impacts. The timing and severity of these potential irreversible climate change impacts are clearly uncertain as is the degree to which near-term lifecycle emissions related to biofuel production influences these climate change impacts. Given these uncertainties, it may be appropriate to limit our analysis horizon to a much shorter time period such as 30 years.

Several disadvantages are also associated with choosing the 30 year time frame to represent both emissions impacts as well as emissions benefits. One key disadvantage is that it ignores the potential sources of GHG emissions impacts of producing biofuel after 30 years such as foregone sequestration from forests that may have been removed which could have continuing impacts even after production of a biofuel has ended. Thus, it doesn't account for the full land use emissions ''signature'' of biofuels. In addition, even if second generation fuels start to dominate new construction, building a first generation fuel production facility such as a corn ethanol refinery represents a significant capital investment. Once the facility is built and financed, it may continue

[291] Luyassert, S *et al.,* 2008. Old-growth forests as global carbon sinks. *Nature* 455: 213–215. Link: *http://www.nature.com/nature/journal/v455/n7210/abs/nature07276.html.*

[292] Searchinger *et al.,* 2008.

[293] M. Delucchi, ''A multi-country analysis of lifecycle emissions from transportation fuels and motor vehicles'' (UCD–ITS–RR–05–10, University of California at Davis, Davis, CA 2005). *See also http://www.its.ucdavis.edu/people/faculty/delucchi/.*

producing biofuel as long as it is covering its operating costs. This suggests that, once a plant is built, if the variable cost of corn ethanol production is less than the cost to produce gasoline, then corn ethanol production at that facility may continue. This economic advantage may contribute to the longevity of first generation biofuel production and usage far into the future.

An appropriate time frame for analysis could also be different for different biofuels. While we could assume that corn ethanol would be phased out after a shorter time period such as 30 years, it might be more appropriate to use a longer time period over which to analyze the benefits of other advanced biofuels such as cellulosic biofuels. It could be reasonably assumed that cellulosic biofuels will be produced for more than 30 years, perhaps for 100 years or longer. However, even if cellulosic biofuels are expected to be produced for 100 years or longer, a shorter time period, such as 30 years, may still be the most relevant period over which to assess GHG emissions, given the importance of near-term emissions reductions and the increasing uncertainty of future events. We specifically seek comments on the 100 year and 30 year time frames discussed in this proposal. We also seek general comments on the most appropriate time periods for analysis of biofuels, and whether we should use different time periods for different types of renewable fuels.

Another way to look at the time period issue, which we have not specifically analyzed for this proposed rule, would separate the time period into two parts. The first part would consider how long we expect production of a particular biofuel to continue into the future. We refer to this concept, which is similar to the project lifetime often considered in traditional cost benefit analysis, as the ''project'' time horizon. The second part would address the length over which to account for the changes in GHG emissions due to land use changes which result from biofuel production. We call this the ''impact'' time horizon.

Our analysis for this proposed rule has not considered a scenario where the project time horizon is shorter than impact time horizon. However, we are considering this option for the final rule. For example, we could look at a scenario where corn ethanol production continues for 30 years and land use related GHG emissions are estimated for 100 years. Specifically, we are considering whether to use 30 years after 2015 (as an approximation of when ethanol production from corn starch reaches 15 billion gallons) as a reasonable estimate of when corn will no longer be used for ethanol production due to advances in other biofuels and the competing demand to use corn for food rather than biofuel feedstock. We specifically ask whether a 30 year estimate of continued corn starch ethanol production (i.e., through 2045) is a reasonable estimate for assessing the stream of GHG benefits from corn ethanol use while 100 years would be appropriate for assessing impacts of the land use change. Under such an assumption a 100 time horizon would capture the longer term emission impacts of corn ethanol production (including indirect land use impacts) while the benefits from 31 through 100 years would be zero since corn ethanol would be modeled as no longer in use.

In that scenario, we would have to consider the lifecycle GHG impacts after the production of corn ethanol ends. This would include the issue of land reversion, or what happens to the land used to produce a biofuel feedstock after its use for biofuel production has ceased. A full accounting of land reversion would involve economic modeling to determine how long we expect production of a particular biofuel to last, and to determine the land use changes after that biofuel production ends. Ideally this modeling would extend well beyond 2022 to the point where land reversion is complete, and it would include projections for global crop yield improvements, population trends, food demand, and other key factors. For this proposal, we have not projected the GHG emissions associated with land reversion, but we plan to consider land reversion in our final rule analysis and we seek comments on methodologies and approaches for doing this. We also seek comment on the related issue of how best to estimate how long each type of biofuel is most likely to continue to be produced, and whether production of these biofuels is likely to end abruptly or phase out gradually.

Agricultural and economic models that look beyond 2022 would not only help to estimate the impacts of land reversion after biofuel production ends, they would also help to project how evolving agricultural conditions could influence the lifecycle GHG emissions of biofuels beyond 2022. For example, corn yields per acre are expected to continue increasing after 2022; this increase in yields per acre will decrease the amount of land required to produce a bushel of corn. At higher yields, fewer acres are required to grow the corn used for the 15 billion gallons of corn starch ethanol modeled for the rule. The indirect impacts of maintaining 15 billion gallons of corn ethanol production would similarly be reduced. EPA intends to more carefully model these transitions in particular to better account for future land use impacts and we invite comments on methodology, sources of data, factors that should be considered in assessing whether and when a particular biofuel such as ethanol from corn starch, for example, will no longer be produced and recommendations on how to improve on our assessment of the likely stream of GHG emissions after 2022 that will result from the EISA mandates.

A complicating consideration in this analysis arises in determining future use of the land (post-biofuel production) is the fact that perhaps significant land use change occurred as a result of biofuel production and that land is now more easily suited for alternative uses compared to its pre-biofuel state. For example, the demand created by biofuel production may have justified clearing forested lands and turning them into productive cropland. Even if the need for the land to produce crops in response to biofuel demand ceases when the biofuel production ends, the land will still be in an altered form making it, for example, more economically available for other crop production than when it had been forested. How this land is subsequently used can affect its impact on GHG emissions. If it is used for intensive crop production, the land will have a much different carbon sequestration profile, for example, than if it returned to its pre-biofuel forested state. EPA asks for suggestions on how to best treat these lingering effects of land use change when attributing the effects of biofuel demand to uses of land even after biofuel production ends.

For the determination of whether biofuels meet the GHG emissions reduction required by EISA, we present the results for a range of time periods, including both 100 years and 30 years in Section VI.C and specifically invite comment on whether use of a 100 year time frame, a 30 year time frame, or some other time frame, would be most appropriate.

In addition to this general issue of the appropriate time frames for analysis, several more specific issues exist. Since it would be likely that corn starch ethanol production will phase out gradually rather than stopping all of a sudden in 2045, we also are evaluating options for estimating the phase out of corn starch ethanol production. One simplifying assumption would have corn ethanol production phase out linearly between 2022 and 2045 as production of other biofuels such as cellulosic biofuels continue to expand. Comments are requested on the option of linearly phasing out corn ethanol production from 2022 through 2045 and other approaches for estimating this transition in corn ethanol production. Finally, its not only corn starch ethanol that might be replaced in future years. For example, the use of soy oil for biodiesel fuel production might be replaced by other non-food oils such as oil from algae. Comments are requested on whether other biofuels will similarly phase out of use and therefore the land use change impacts need to be similarly considered.

In addition to seeking comments on all of the issues related to the time periods for lifecycle analysis, EPA plans to convene a peer review of the range of time periods considered in this proposed rule. This peer review will also seek expert feedback on all of the issues raised above in this section, including how to determine the most appropriate time periods for consideration in the final rule.

Discounting of Lifecycle GHG Emissions

Economic theory suggests that in general consumers have a time preference for benefits received today versus receiving them in the future. Therefore, future benefits are often valued at a discounted rate. Although discount rates are most often applied to the monetary valuation of future versus present benefits, a discounting approach can also be used to compare physical quantities (i.e., total GHG emissions per gallon of fuel used).

The concept of weighting physical units accruing at different times has been used in the environmental and resource economics literature,[294] and is analogous to valuing the monetary cost and benefits of a policy, only that in this case the metric that we 'value' is the reduction in GHG emissions. [295] An important part of the economic theory of time is the idea that benefits expected to accrue in the long term are less certain than benefits in the near term. This is true in the case of GHG emissions changes from biofuel production which are dependent upon how long biofuel production will continue, how technologies will develop over time, and other factors.

Another reason to give more weight to near-term emissions changes is that the risks associated with climate change in the future include the possibility of extreme climate change and threshold impacts (e.g., species and ecosystem thresholds, catastrophic events). Increased GHG emissions in the near-term may be more important in terms of physical damage to the world's environment. Some scientists, for example, believe that effects on factors such as arctic summer ice, Himalayan-Tibetan Glaciers, and the Greenland ice sheet are more likely to be effected by near-term GHG emissions, causing non-linearities in the effects attributable to GHG emissions.[296] Long-term GHG reductions may be too late to mitigate these irreversible impacts, providing further justification for discounting GHG emissions changes that are expected in the distant future. Under this perspective, it would be appropriate to discount the physical quantities of future emissions, and especially in a long term analysis of lifecycle GHG emissions. Thus in our analysis with a 100 year time frame, or impact horizon, we discount the value of future GHG emissions changes.

Despite the rationale for discounting future GHG emissions changes discussed above, there are reasons to be cautious about the application of discounting in lifecycle GHG analysis. One argument is that it may only be appropriate to discount monetized values. Our lifecycle analysis estimates GHG emission impacts, not their monetary value, and under this argument emissions should not be directly discounted. Rather, the physical GHG emissions should be converted into monetary impacts, where these monetary impacts are also a function of climate science. The resulting climate impacts would then have to be translated into monetary values. This presents significant challenges for lifecycle GHG analysis because it is difficult to translate dynamic GHG emissions into a single estimate of physical impacts, much less a single estimate of monetized impacts. This is the case for a number of reasons, including the complex physical systems associated with climate change (e.g., the relationship between atmospheric degradation rates with atmospheric carbon stocks) that may create non-constant marginal damages from GHG emissions over time. Furthermore, converting lifecycle GHG emissions into monetized impacts may be inconsistent with the EISA definition of lifecycle GHG emissions provided above in Section VI.A.1, which stipulates that lifecycle GHG emissions are the ''aggregate quantity of greenhouse gas emissions * * * where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential.''

Another argument against discounting GHG emissions changes is the concept of inter-generational equity, which argues that benefits or damages affecting future generations merit just as much weight as impacts felt by current generations. It is argued that this would invalidate the practice of discounting emissions impacts that could affect future generations.

Finally, earlier in this section we discussed the possible ranges of time frames for analyzing the GHG emissions impacts. For shorter time frames such as 30 years, there would be less uncertainty in the emissions stream so the benefit of discounting to address uncertainty is also lessoned.

Comments are requested on the concept of discounting a stream of GHG emissions for the purpose of estimating lifecycle GHG emissions from transportation fuels as specified in EISA.

Appropriate Level of Discount Rate

As described in more detail in Section IX on GHG emission reduction benefits, GHG emissions have primarily consumption effects and inter-generational impacts, as changes in GHG emissions today will continue to have impacts on climate change for decades to centuries. If a discount rate is applied to future GHG emissions, an appropriate discount rate should be based on a consumption-based discount rate given that monetized climate change impacts are primarily consumption effects (i.e., impacts on household purchases of goods and services). A consumption-based discount rate reflects the implied tradeoffs between consumption today and in the future. Discount rates of 3% or less are considered appropriate for discounting climate change impacts, since they reflect the long run uncertainty in economic growth and interest rates and the risk of high impact climate damages that could reduce economic growth.[297]

[294] Herzog *et al.* 2003 (*See http://sequestration.mit.edu/pdf/climatic_change.pdf*), Richards 1997, Stavins and Richards 2005 (*See http://www.pewclimate.org/docUploads/Sequest_Final.pdf*).

[295] Sunstein and Rowell, 2007, On Discounting Regulatory Benefits: Risk, Money, and Intergenerational Equity, *Chicago Law Review*.

[296] Ramanathan and Feng, 2008. On avoiding dangerous anthropogenic interference with the climate system: Formidable challenges ahead. *Proceedings of the National Academy of Sciences* 105:143245–14250.

[297] *Technical Support Document on Benefits of Reducing GHG Emissions,* U.S. Environmental Protection Agency, June 12, 2008, *www.regulations.gov* (search phrase ''Technical

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When analyzing the GHG emissions associated with a 100 year time period, we examined a variety of alternative discount rates (e.g., 0, 2, 3, 7 percent) to show the sensitivity of greenhouse gas emissions estimates to the choice of the discount rate. A zero discount rate estimates GHG emission impacts as if each ton of GHG emissions is treated equally through time. Previous methodologies of lifecycle GHG benefits have presented results using a zero discount rate.[298] However, some of the climate change literature supports using a higher discount rate, as described in Section IX.C. We show the 7% discount rate for illustrative purposes; however climate change benefit analyses from global long-run growth models typically use discount rates well under 7% for standard analysis.[299] High discount rates imply very low values for the future GHG emission impacts resulting from today's actions on the welfare of future generations. Therefore, lower discount rates such as 2–3% are considered more appropriate for discounting long term climate change impacts.[300]

In the analysis for this proposal we use a 2% discount rate to assess the present value of GHG emissions changes which occur over a 100 year time frame. This discount rate is consistent with the Office of Management and Budget (OMB)[301] and EPA[302] guidance and is one of the discount rates that has been used in the literature to monetize the impacts of climate change.[303] EPA has considered this issue previously, and after weighing the pros and cons of different values, set forth a guidance document recommending using a range of consumption based discount rates of 0.5–3%. OMB and EPA guidance on inter-generational discounting suggests using a low but positive discount rate if there are important inter-generational benefits and costs. In selecting a 2% discount rate coupled with a 100 year emission stream estimate, EPA would be recognizing the long term nature of the emission impacts of biofuel production, the uncertainty in estimating these emission impacts and their consequences plus the significance of nearer term emission changes in avoiding future consequences. Other options for intergenerational discounting have been discussed in the economic literature, such as dealing with uncertainty by using a non-constant, declining, or negative discount rate.[304] Comments could consider how discounting appropriately reflects the uneven emission of greenhouse gases from biofuels over time, the uncertainty in predicting emissions in more distant futures and the impacts these emissions could have on climate change. Alternative approaches for inter-generational discounting are described in Chapter 5.3 of the DRIA.

Because we are considering not discounting GHG emissions and in particular since the justifications for discounting physical emissions are not as strong for shorter time periods, in Section VI.C.2, we also present the GHG emissions reductions associated with biofuels using a 30 year time period and no discount rate. Using a zero percent or no discount rate implies that all emission releases and uptakes during this time period are valued equally. For a shorter time period such as thirty years, we are relatively certain of the emission trends. Furthermore, all of these emissions occur in a relatively short period of time so their impact on climate change and the consequences of that climate change could all be considered the same regardless of whether those emissions occurred early or late in this 30-year time period.

We specifically invite comment on our use of a 2% discount rate with a 100 year time period for analysis of lifecycle GHG emissions, and our use of no discount rate in our analysis of GHG emissions over 30 years. We also invite comments on whether using physical science metrics such as the actual quantities of climate forcing gasses in the atmosphere, actual quantities of climate forcing gasses in the atmosphere weighted by global warming potential (GWP), or cumulative radiative forcing should be used to evaluate emissions over time. Specifically, we seek comment on an approach for comparing GHG emissions based on the time profile of the greenhouse gas emissions in the atmosphere, and whether this approach would be consistent with the legal definition of lifecycle GHG emissions in EISA. One such method is the Fuel Warming Potential as outlined in a memo to the EPA from the Union of Concerned Scientists which is available on the public docket for this rulemaking.[305] This approach is based on the ratio of the cumulative radiative forcing between the biofuel and the gasoline case over a specified time frame.

The EISA definition of lifecycle GHG emissions stipulates that the mass values for all greenhouse gas emissions shall be adjusted to account for their relative GWP. We are proposing to use the standard 100-year GWP's published in the IPCC Second Assessment Report.[306] [307] We invite comment on whether it is appropriate to discount GWP-weighted emissions and how such discounting might appropriately apply across the several greenhouse gases.

Furthermore, if alternative time periods for the production of biofuels and the GHG impacts of biofuel production are considered as discussed above, and the choice is made to discount GHG emissions, the question that arises is: What discount rate or combination of discount rates should be considered? For example, if ethanol production is assumed to occur for 30 years and the GHG impacts are assumed to span across 80–100 years, should a single discount rate be applied to the emissions stream or alternative discount rates based upon the different time frames? EPA is taking comment on whether and how to apply discounting when different time frames between the production and long-run GHG impacts are utilized to analysis biofuels. Specifically, EPA is considering and requests comment on the option of using either no discount rate or a 3% discount rate to assess those emissions that occur during the relatively shorter time frame for biofuel use which could phase out within 30 years as in our corn ethanol example and a 2% discount rate over the reminder of the 100 years in assessing the longer term GHG emissions impacts resulting from land use changes related to biofuel production (including land reversion considerations).

EPA is considering a range of discount rates including zero or no discounting for reasons as described above and requests comments on the appropriate discount rate to use when assessing the stream of GHG emission changes that are likely to result from biofuel production and use. Other

Support Document on Benefits of Reducing GHG Emissions'').

[298] Searchinger *et al.,* 2008.

[299] Tol, 2005.

[300] Newell and Pizer, 2003.

[301] OMB Circular A–4, 2003 provides a range of 1–3% for consumption based discount rates.

[302] EPA Guidelines for Preparing Economic Analyses, 2000.

[303] Tol (2005, 2007).

[304] Newell and Pizer, 2003, Weitzman (1999, 2001), Nordhaus (2008), Guo *et al.,* (2006), Saez, C.A. and J.C. Requena, ''Reconciling sustainability and discounting in Cost-Benefit Analysis: A methodological proposal'', *Ecological Economics,* 2007, vol. 60, issue 4, pages 712–725.

[305] *See* Memo to EPA, Office of Transportation and Air Quality from Union of Concerned Scientists, Re: Treatment of Time in Life Cycle Accounting, February 18, 2009.

[306] *See http://www.ipcc.ch/ipccreports/assessments-reports.htm*.

[307] O'Hare, Plevin, Martin, Jones, Kendal and Hopson; ''Proper accounting for time increases crop-based biofuel's greenhouse gas deficit versus petroleum''; Environmental Research Letters, 4 (2009) 024001.

options for intergenerational discounting have been discussed in the economic literature, such as dealing with uncertainty by using a non-constant, declining, or negative discount rate.[308] Comments could consider how discounting appropriately reflects the uneven release of greenhouse gases from biofuels over time, the uncertainty in predicting emissions in more distant futures and the impacts these emissions could have on climate change. Alternative approaches for inter-generational discounting are described in Chapter 5.3 of the DRIA.

EPA recognizes that the time horizon for analysis and the treatment of future emissions including the appropriateness of applying discount factors are key factors in determining biofuel lifecycle GHG impacts; therefore, we plan to organize an expert peer review of these issues before the final rule.

c. Feedstock Transport

The GHG impacts of transporting corn from the field to the ethanol facility and transporting the co-product DGs from the ethanol facility to the point of use were included in this analysis. The GREET default of truck transportation of 50 miles was used to represent corn transportation from farm to plant. Transportation assumptions for DGs transport were 14% shipped by rail 800 miles, 2% shipped by barge 520 miles, and 86% shipped by truck 50 miles. The percent shipped by mode was from data provided by USDA and based on Association of American Railroads, Army Corps of Engineers, Commodity Freight Statistics, and industry estimates. The distances DGs were shipped were based on GREET defaults for other commodities shipped by those transportation modes. The GHG emissions from transport of corn and DGs are based on GREET default emission factors for each type of vehicle including capacity, fuel economy, and type of fuel used. Similar detailed analyses were conducted for the transport of cellulosic biofuel feedstock and biomass-based diesel feedstock.

As part of this rulemaking analysis we have conducted a more detailed analysis of biofuel production locations and transportation distances and modes of transport used in the criteria pollutant emissions inventory calculations described in DRIA Chapter 1.6 and for the cost analysis of this rule described in DRIA Chapter 4.2. Given the timing of when the current analysis was completed we were not able to incorporate this updated transportation information into our lifecycle analysis but plan to do that for the final rule.

Furthermore, the transportation modes and distances assumed for corn and DGs do not account for the secondary or indirect transportation impacts. For example, decreases in exports might reduce overall domestic agricultural commodity transport and emissions but might increase transportation of commodities internationally. We plan to consider these secondary transportation impacts in our final rule analysis.

d. Processing

The GHG emissions estimates associated with the processing of renewable fuels is dependent on a number of assumptions and varies significantly based on a number of key variables. The ethanol yield impacts the total amount of corn used and associated agricultural sector GHG emissions. The amount of DGs and other co-products produced will also impact the agricultural sector emissions in terms of being used as a feed replacement. Finally the energy used by the ethanol plant will result in GHG emissions, both from producing the fuel used and through direct combustion emissions.

As mentioned above, in traditional lifecycle analyses, the energy consumed and emissions generated by a renewable fuel plant must be allocated not only to the renewable fuel, but also to each of the by-products. For corn ethanol production, our analysis avoids the need to allocate by accounting for the DGs and other co-products directly in the FASOM and FAPRI agricultural sector modeling described above. DGs are considered a partial replacement for corn and other animal feed and thus reduce the need to make up for the corn production that went into ethanol production. Since FASOM takes the benefits from the production and use of DGs into account (e.g., displacing the need to grow additional crops for feed and therefore reducing GHG emissions in the agricultural sector), no further allocation was needed at the ethanol plant and all plant emissions are accounted for here.

In terms of the energy used at renewable fuel facilities, there is a lot of variation between plants based on the process type (e.g., wet vs. dry milling) and the type of fuel used (e.g., coal vs. natural gas). There can also be variation between the same type of plants using the same fuel source based on the age of the plant and types of processes included, etc. For our analysis we considered different pathways for corn ethanol production. Our focus was to differentiate between facilities based on the key differences between plants, namely the type of plant and the type of fuel used. One other key difference we modeled between plants was the treatment of the co-products DGs. One of the main energy drivers of ethanol production is drying of the DGs. Plants that are co-located with feedlots have the ability to provide the co-product without drying. This has a big enough impact on overall results that we defined a specific category for wet vs. dry co-product. One additional factor that appears to have a significant impact on GHG emissions is corn oil fractionation from DGs. Therefore, this category is also broken out as a separate category in the following section. See DRIA Chapter 1.4 for a discussion of corn oil fractionation.

Furthermore, as our analysis was based on a future timeframe, we modeled future plant energy use to represent plants that would be built to meet requirements of increased ethanol production, as opposed to current or historic data on energy used in ethanol production. The energy use at dry mill plants was based on ASPEN models developed by USDA and updated to reflect changes in technology out to 2022 as described in DRIA Chapter 4.1.

The GHG emissions from renewable fuel production are calculated by multiplying the Btus of the different types of energy inputs by emissions factors for combustion of those fuel sources. The emission factors for the different fuel types are from GREET and are based primarily on assumed carbon contents of the different process fuels. The emissions from producing electricity are also taken from GREET and represent average U.S. grid electricity production emissions. The emissions from combustion of biomass fuel source are not assumed to increase net atmospheric CO_2 levels the CO_2 emitted from biomass-based fuels combustion does not increase atmospheric CO_2 concentrations, assuming the biogenic carbon emitted is offset by the uptake of CO_2 resulting from the growth of new biomass. Therefore, CO_2 emissions from biomass combustion as a process fuel source are not included in the lifecycle GHG inventory of the ethanol plant.

e. Fuel Transport

Transportation and distribution of ethanol, biomass-based diesel, petroleum diesel and gasoline were also included in this analysis based on GREET defaults. The GREET defaults for

[308] Newell and Pizer, 2003, Weitzman (1999, 2001), Nordhaus (2008), Guo *et al.,* (2006), Saez, C.A. and J.C. Requena, ''Reconciling sustainability and discounting in Cost-Benefit Analysis: A methodological proposal'', *Ecological Economics,* 2007, vol. 60, issue 4, pages 712–725.

both ethanol and gasoline transport from plant/refinery to bulk terminals were used. The GREET defaults for both ethanol and gasoline distribution from the bulk terminal to the service station were also used.

As with feedstock transport we have conducted a more detailed analysis of fuel transport and distribution impacts for use in criteria pollutant inventories (see DRIA Chapter 1.6) and for our cost analysis described in DRIA Chapter 4.2. Due to the timing of this analysis we were not able to incorporate the results in our proposed lifecycle calculation but plan to do that for the final rule.

f. Tailpipe Combustion

Combustion CO_2 emissions for ethanol, biomass-based diesel, petroleum diesel and gasoline were based on the carbon content of the fuel. However, over the full lifecycle of the fuel, the CO_2 emitted from biomass-based fuels combustion does not increase atmospheric CO_2 concentrations, assuming the biogenic carbon emitted is offset by the uptake of CO_2 resulting from the growth of new biomass. As a result, CO_2 emissions from biomass-based fuels combustion are not included in their lifecycle emissions results. Net carbon fluxes from changes in biogenic carbon reservoirs in wooded or crop lands are accounted for separately in the land use change analysis as outlined in the agricultural sector modeling above.

When calculating combustion GHG emissions, however, the methane and N_2O emitted during biomass-based fuels combustion are included in the analysis. Unlike CO_2 emissions, the combustion of biomass-based fuels does result in net additions of methane and N_2O to the atmosphere. Therefore, combustion methane and N_2O emissions are included in the lifecycle GHG emissions results for biomass-based fuels.

Combustion related methane and N_2O emissions for both biomass-based fuels and petroleum-based fuels are based on EPA MOVES model results.

6. Petroleum Baseline

To establish the lifecycle greenhouse gas emissions associated with the petroleum baseline against which the renewable fuels were compared, we used an updated version of the GREET model. Lifecycle energy use and associated emissions for petroleum-based fuels in GREET is calculated based on an energy efficiency metric for the different processes involved with petroleum-based fuels production. The energy efficiency metric is a measure of how many Btus of input energy are needed to make a Btu of product. GREET has assumptions on energy efficiency for different finished petroleum products as well as for different types of crude oil.

We are using the latest version of the GREET model for this analysis (Version 1.8b) which includes recent updates to the energy efficiencies of petroleum refining. To represent baseline petroleum fuels we have used the 2005 estimates of actual gasoline and diesel fuel used. For 2005, 86% of gasoline and 92% of diesel fuel was produced domestically with the rest imported finished product. To represent international production we assume the same GHG refinery emissions from GREET as used domestically. We did not include indirect land use impacts in assessing the lifecycle GHG performance of the 2005 baseline fuel pool as we believe these would insignificantly impact the average performance assessment of the baseline. Additionally, consistent with our assessment of energy security impacts, we did not include as an indirect GHG impact the potential impact of maintaining a military presence.

GREET also has assumptions on the mix of energy sources used to provide the energy input, which determine GHG emissions. For example if coal, natural gas, or purchased electricity is used as an energy source. The GHG emissions associated with petroleum fuel production are based on the emissions from producing and combusting the input energy sources needed, like GHG emissions from using natural gas at the petroleum refinery. Non-combustion GHG sources like fugitive methane emissions are added in where applicable.

Based on the EISA requirements, we used the 2005 mix of crude as the petroleum baseline. We developed emissions factors for those crude types since they are not currently included in GREET. In 2005, 5% of crude was Canadian tar sand, 1% was Venezuela extra heavy, and 23% was heavy crude.

For this proposal, we are using the average GHG emissions associated with the 2005 petroleum baseline, as required by EISA. However, we recognize that an additional gallon of renewable fuel replaces the marginal gallon of petroleum fuel. To the extent that the marginal gallon is from oil sands or other types of crude oil that are associated with higher than average GHG emissions, replacing these fuels could have a larger GHG benefit. Conversely to the extent the marginal gallon displaced is from imported gasoline produced from light crude, replacing these fuels would have a smaller GHG benefit. We solicit comment on whether—strictly for purposes of assessing the benefits of the rule (and not for purposes of determining whether certain renewable fuel pathways meet the GHG reduction thresholds set forth in EISA), we should assess benefits based on a marginal displacement approach and, if so, what assumptions we should use for the marginal displacements.

In December 2008, the U.S. Department of Energy's National Energy Technology Laboratory (NETL) released a report that estimates the average lifecycle GHG emissions from petroleum-based fuels sold or distributed in 2005.[309] The estimates in the report are based on a slightly different methodology than EPA's analysis of lifecycle GHG emissions for the petroleum baseline. The NETL report is available on the docket for this rulemaking. We invite comments on whether NETL's analysis has significant implications for how EPA is estimating petroleum baseline lifecycle GHG emissions.

7. Energy Sector Indirect Impacts

Increased demand for natural gas to power corn ethanol plants could have additional impacts on the U.S. energy sector. As demand for natural gas increases, the use of natural gas in other sectors (e.g., electric generation) could decrease. For this analysis, we are using the NEMS model to project the secondary or indirect impacts on the energy sector. However, we were not able to include this analysis in the GHG emissions estimates presented in this proposal. We hope to have this analysis for the final rule. Additional details on the methodology are included in the DRIA Chapter 2, and we invite comments on this approach.

We are assuming, for the proposal, that a gallon of renewable fuel replaces an energy equivalent gallon of petroleum fuel. This analysis presumes that petroleum-based fuels as they are currently produced will continue to be used for transportation fuels and will be replaced on a Btu for Btu basis. Many factors could affect this assumption including advances in petroleum fuel technology, availability of other fossil fuels for transportation use, and of course the supply and cost of petroleum. We have not tried to analyze these potential impacts in this rule. However we invite comment on such an approach.

We have also not assessed whether expanded use of biofuels in the U.S.

[309] DOE/NETL. 2008. Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels. DOE/NETL–2009/1346.

will impact the energy markets in other countries. For example, reducing demand for petroleum-based fuel in the U.S. may reduce worldwide petroleum prices and impact the use of petroleum in other countries. We invite comment on how best to assess these potential impacts and will attempt to do so for the final rule.

C. Fuel Specific GHG Emissions Estimates

While the results presented in this section represent the most up-to-date information currently available, this analysis is part of an ongoing process. Because lifecycle analysis is a new part of the RFS program, in addition to the formal comment period on the proposed rule, EPA is making multiple efforts to solicit public and expert feedback on our proposed approach. As discussed in Section XI, EPA plans to hold a public workshop focused specifically on lifecycle analysis during the comment period to assure full understanding of the analyses conducted, the issues addressed and options that should be considered. We expect that this workshop will allow the most thoughtful and useful comments to this proposal and assure the best methodology and assumptions are used for calculating GHG emissions impacts of fuels for the final rule. Additionally we will conduct peer-reviews of key components of our analysis. As part of ongoing analysis for the final rule, EPA will seek peer review of: Our use of satellite data to project future land use changes; the land conversion GHG emissions factors estimated by Winrock; our estimates of GHG emissions from foreign crop production; methods to account for the variable timing of GHG emissions; and how models are used together to provide overall lifecycle GHG estimates.

In addition to the refinements to the methodology that we plan to undertake for the final rule, we also intend to update our results periodically. EPA recognizes that the state of the science for lifecycle GHG analysis will continue to evolve over time as new data and modeling techniques become available and as there are improvements in agricultural and renewable fuel production practices as well as new feedstocks. We invite comments on the appropriate amount of time for periodic review of the lifecycle assessment methodology, but we propose that performing an update of the methodology every 3–5 years would be appropriate. We would expect the first update to this analysis would occur closer to 3 years. This timeframe would allow us to undergo a formal review process after the final rule to ensure that this methodology takes into account the most state-of-the-art science and reflects the input of appropriate experts in this field. However, any change in lifecycle methodology as contemplated here would not affect the eligibility of biofuels produced at facilities covered by the grandfathering provisions of EISA at section 211(o)(4)(g).

1. Greenhouse Gas Emissions Reductions Relative to the 2005 Petroleum Baseline

In this section we present detailed lifecycle GHG results for several specific biofuels representing a range biofuel pathways. This section also includes the results of sensitivity analysis for key variables. The sensitivity of the time period and discount rate are discussed below. In the rest of this section we focus on two sets of lifecycle GHG results. One set of results that uses a 100 year time period and 2% discount rate and a parallel set of results using a 30 year time period and a 0% discount rate. In Section IV.C.2 which follows, we also present the results for some additional combinations of time horizon for assessing GHG emission changes as well as assuming other discount rates. Additional pathways, not included in the results presented in this section, distinguishing other combinations of feedstock and processing technologies have been evaluated. These additional pathways are described in detail in the DRIA and are included in these proposed regulations.

a. Corn Ethanol

Table VI.C.1–1 presents the breakout of the net present value of lifecycle GHG emissions per million British thermal unit (mmbtu) of corn ethanol and gasoline. The results are broken out by lifecycle stage. Values are shown for a standard dry mill corn ethanol plant in 2022 using natural gas for process energy and drying the co-product of distillers grains (DGs). Results indicate where the major contributions of GHG emissions are across the fuel lifecycle. Fuel processing and indirect land use change are the main contributors to corn ethanol lifecycle GHG emissions. Net domestic and international agricultural impacts (w/o land use change) include direct and indirect impacts, such as reductions in livestock enteric fermentation.

TABLE VI.C.1–1—ABSOLUTE LIFECYCLE GHG EMISSIONS FOR CORN ETHANOL AND THE 2005 PETROLEUM BASELINE

[CO_2-eq/mmBtu]

	2005 Gasoline baseline	Natural gas dry mill with dry DGs	2005 Gasoline baseline	Natural gas dry mill with dry DGs
Lifecycle Stage	100 yr 2%		30 yr 0%	
Net Domestic Agriculture (w/o land use change)	N/A	−499,029	N/A	−347,365
Net International Agriculture (w/o land use change)	N/A	452,118	N/A	314,711
Domestic Land Use Change	N/A	79,547	N/A	92,575
International Land Use Change	N/A [310]	1,911,391	N/A	1,910,822
Fuel Production [311]	823,262	1,404,083	573,058	977,358
Fuel and Feedstock Transport	(see footnote 321)	174,327		121,346
Tailpipe Emissions [312]	3,417,311	37,927	2,378,800	26,400
Net Total Emissions	4,240,674	3,560,365	2,951,858	3,095,846

[310] For this proposal, our preliminary analysis suggests land use impacts of petroleum production for the fuels used in the U.S. in 2005 would not have an appreciable impact on the 2005 baseline GHG emissions assessment. However, we expect to more carefully consider potential land use impacts of petroleum-based fuel production for the final rule and invite comment and information that would support such an analysis.

[311] 2005 petroleum baseline fuel production includes crude oil extraction, transportation, refining, and transport of finished product.

[312] Ethanol tailpipe emissions include CH_4 and N_2O emissions but not CO_2 emissions as these are assumed to be offset by feedstock carbon uptake.

Table VI.C.1–1 demonstrates the importance of the discount rate and time period analyzed as well as the importance of significance of including GHG emissions from international land use changes. Assuming 100 years of corn ethanol produced in a basic dry mill ethanol production facility and using a 2% discount rate results in corn ethanol having a 16% reduction in GHG emissions compared to the 2005 baseline gasoline assumed to be replaced. In contrast, assuming 30 years of corn ethanol production and use and no discounting of the GHG emission impacts results in predicting that corn ethanol will have a 5% increase in GHG emissions compared to petroleum gasoline.

As discussed in Section VI.B.2.a, EPA's interpretation of the EISA statute compels us to include significant indirect emission impacts including those due to land use changes in other countries. The data in Table VI.C.1–1 indicate that excluding the international land use change would result in corn ethanol having an approximately 60% reduction in lifecycle GHG emissions compared to petroleum gasoline regardless of the timing or discount rate used.[313]

In Table VI.C.1–1, we project a standard dry mill ethanol plant in 2022 using corn as its feedstock, using natural gas for process energy, and drying the co-product of distillers grains (DGs). Different corn ethanol production technologies will have different lifecycle GHG results. For example, due to its high carbon content, using coal as the process energy source significantly worsens the lifecycle GHG impact of ethanol produced at such a facility. On the other hand, replacing natural gas with renewable biomass as the process energy source greatly improves the GHG assessment.

Other technology options are available to improve the efficiency of ethanol facilities. Table VI.C.1–2 shows the impact that different corn ethanol production process pathways will have on the overall lifecycle GHG results. Table VI.C.2–2 shows that currently available technologies could be applied to corn ethanol plants to reduce their net GHG emissions.

For example, a combined heat and power (CHP) configuration, used in combination with corn oil fractionation, would result in a GHG emissions reduction of 27% relative to the 2005 petroleum baseline over 100 years using a 2% discount rate, and a 6% reduction over 30 years with no discounting. In addition, advanced technologies such as membrane separation and raw starch hydrolysis could improve the emissions associated with corn ethanol production even more substantially. Combining all of these technologies in a state-of-the-art natural gas powered corn ethanol facility would produce ethanol that has approximately 35% less lifecycle GHG emissions than an energy equivalent amount of baseline gasoline displaced over 100 years using a 2% discount rate and, by comparison a 14% reduction when accounting for 30 years of emission changes but applying no discounting. Details on these different technologies are included in the DRIA Chapter 1.5.

Table VI.C.1–2 also shows that the choice of drying DGs can have a significant impact on the GHG emissions associated with an ethanol plan, since drying the ethanol byproduct is an energy intensive process. However, wet DGs are only suitable where a local market is available such as a dairy farm or cattle feedlot, since wet DGs are highly perishable.

TABLE VI.C.1–2—LIFECYCLE GHG EMISSIONS CHANGES FOR VARIOUS CORN ETHANOL PATHWAYS IN 2022 RELATIVE TO THE 2005 PETROLEUM BASELINE

Corn ethanol production plant type	Percent change from 2005 petroleum baseline (100 yr 2%)	Percent change from 2005 baseline (30 yr 0%)
Natural Gas Dry Mill with dry DGs	−16	+5
Natural Gas Dry Mill with dry DGs and CHP	−19	+2
Natural Gas Dry Mill with dry DGs, CHP, and Corn Oil Fractionation	−27	−6
Natural Gas Dry Mill with dry DGs, CHP, Corn Oil Fractionation, and Membrane Separation	−30	−10
Natural Gas Dry Mill with dry DGs, CHP, Corn Oil Fractionation, Membrane Separation, and Raw Starch Hydrolysis	−35	−14
Natural Gas Dry Mill with wet DGs	−27	−6
Natural Gas Dry Mill with wet DGs and CHP	−30	−9
Natural Gas Dry Mill with wet DGs, CHP, and Corn Oil Fractionation	−33	−12
Natural Gas Dry Mill with wet DGs, CHP, Corn Oil Fractionation, and Membrane Separation	−36	−15
Natural Gas Dry Mill with wet DGs, CHP, Corn Oil Fractionation, Membrane Separation, and Raw Starch Hydrolysis	−39	−18
Coal Fired Dry Mill with dry DGs	+13	+34
Coal Fired Dry Mill with dry DGs and CHP	+10	+31
Coal Fired Dry Mill with dry DGs, CHP, and Corn Oil Fractionation	−5	+15
Coal Fired Dry Mill with dry DGs, CHP, Corn Oil Fractionation, and Membrane Separation	−13	+8
Coal Fired Dry Mill with dry DGs, CHP, Corn Oil Fractionation, Membrane Separation, and Raw Starch Hydrolysis	−21	−1
Coal Fired Dry Mill with wet DGs	−9	+12
Coal Fired Dry Mill with wet DGs and CHP	−11	+10
Coal Fired Dry Mill with wet DGs, CHP, and Corn Oil Fractionation	−17	+3
Coal Fired Dry Mill with wet DGs, CHP, Corn Oil Fractionation, and Membrane Separation	−25	−4
Coal Fired Dry Mill with wet DGs, CHP, Corn Oil Fractionation, Membrane Separation, and Raw Starch Hydrolysis	−30	−9
Biomass Fired Dry Mill with dry DGs	−39	−18
Biomass Fired Dry Mill with wet DGs	−40	−19
Natural Gas Fired Wet Mill	−7	+14

[313] The treatment of emissions over time is not critical if international land use change emissions are excluded because the results without land use change are consistent over time. Therefore the overall lifecycle GHG results do not vary with time or discount rate assumptions.

TABLE VI.C.1–2—LIFECYCLE GHG EMISSIONS CHANGES FOR VARIOUS CORN ETHANOL PATHWAYS IN 2022 RELATIVE TO THE 2005 PETROLEUM BASELINE—Continued

Corn ethanol production plant type	Percent change from 2005 petroleum baseline (100 yr 2%)	Percent change from 2005 baseline (30 yr 0%)
Coal Fired Wet Mill	+20	+41
Biomass Fired Wet Mill	−47	−26

As described in Sections VI.A and VI.B, there are a number of parameters and modeling assumptions that could impact the overall renewable fuel GHG results. The estimates in Table VI.C.1–2 are based on the GHG emissions for a specific change in volumes analyzed in 2022 (12.3 to 15 Bgal). These volumes represent the change in corn ethanol production that would occur in 2022 without and then with EISA mandates in place. The GHG impact is then normalized to a per gallon or Btu basis in relation to gasoline. These values are used to represent every gallon of corn ethanol produced throughout the program.

There are several important implications associated with this methodology. First, this analysis focuses on the average impact of an increase in fuel produced using a technology pathway and does not distinguish the emission performance between biofuel production plants using the same basic production technology and type of feedstock. Thus it does not account for any incremental differences in facility design or operation which may affect the lifecycle GHG performance at that facility. Second, by focusing on 2022, this analysis does not track how biofuel GHG emission performance may change over time between now and 2022. Third, the results presented here are based on the GHG impacts of the volumes analyzed.

For this proposal, we believe that using the emissions assessment from a typical 2022 facility for each major technology pathway captures the appropriate level of detail needed to determine whether a particular biofuel meets the threshold requirements in EISA. To address whether the GHG emissions vary significantly over time, we also calculated corn ethanol lifecycle GHG emissions estimates in 2012 and 2017. As shown in Table VI.C.1–3, corn ethanol's lifecycle GHG emissions reductions are fairly consistent regardless of which base year is analyzed. This may be due to countervailing forces that stabilize land use change emissions over the period of our analysis. Crop yields increase over time (therefore reducing land use pressure), but there is also increasing production of other renewable fuels that require land for feedstock production (therefore increasing land use pressure). Although we are proposing to use 2022 as the base year for our lifecycle GHG emissions estimates, we invite comments on this approach.

TABLE VI.C.1–3—CORN ETHANOL LIFECYCLE GHG EMISSIONS CHANGES IN 2012, 2017, AND 2022

Scenario Description	Percent change from 2005 petroleum baseline (100 yr 2%)	Percent change from 2005 petroleum baseline (30 yr 0%)
Corn Ethanol Natural Gas Dry Mill in 2012 with dry DGs	−16	−3
Corn Ethanol Natural Gas Dry Mill in 2017 with dry DGs	−13	+9
Corn Ethanol Natural Gas Dry Mill in 2022 with dry DGs	−16	+5

We also tested the impact of analyzing a larger change in corn ethanol volumes on the GHG emissions estimates. Table VI.C.1–4 shows the sensitivity of our analysis to the volume changes analyzed. Based on this scenario, the GHG emissions estimates associated with a larger change (6.3 Bgal) in corn ethanol volumes (8.7 Bgal to 15 Bgal) results in lower GHG emission reductions. Additional details on these sensitivity analyses are included in the DRIA Chapter 2.

TABLE VI.C.1–4—CORN ETHANOL LIFECYCLE GHG EMISSIONS CHANGES ASSOCIATED WITH DIFFERENT VOLUME CHANGES

Scenario Description	Percent Change from 2005 Petroleum Baseline (100 yr 2%)	Percent Change from 2005 Petroleum Baseline (30 yr 0%)
Corn Ethanol Natural Gas Dry Mill in 2022 with dry DGs; 2.7 Bgal change in corn ethanol volumes	−16	+5
Corn Ethanol Natural Gas Dry Mill in 2022 with dry DGs; 6.3 Bgal change in corn ethanol volumes	−6	+14

The results presented in previous tables assume that managed pasture (i.e., land actively used for livestock grazing) converted from pasture to cropland would be replaced with new pasture in other areas. The area of managed pasture converted to cropland was estimated using satellite data from Winrock and land cover data from GTAP. As a sensitivity analysis, we also analyzed a scenario in which none of the pastureland converted to cropland would be replaced if, for example, livestock production could be more intensively developed on the remaining pasture (*see* first row in Table VI.C.1–5). Similarly, we also calculated results assuming that all pasture acres would be replaced (second row in Table VI.C.1–5). Finally, the third row of Table VI.C.1–5 includes lifecycle GHG results assuming that all of the land converted to cropland would come from pasture and that none of that pasture would be replaced, which is counter to the land use trends identified by the Winrock satellite data. As can be seen, the assumption of pastureland replacement can have a significant effect on the results. We ask for comment on the best assumptions to be made when considering the need to replace pasture that has been converted to crop production. We note that the best decision on pasture land replacement may vary by country or region due to such factors as the current intensity of use of pasture land as well as trends in demand for pasture. DRIA Chapter 2 includes more details about the treatment of pasture conversion, and sensitivity analysis of the types land use changes induced by corn ethanol production.

TABLE VI.C.1–5—CORN ETHANOL LIFECYCLE GHG EMISSIONS CHANGES ASSOCIATED WITH DIFFERENT ASSUMPTIONS ON LAND USE CHANGES

Scenario Description	Percent Change from 2005 Petroleum Baseline (100 yr 2%)	Percent Change from 2005 Petroleum Baseline (30 yr 0%)
Corn Ethanol Natural Gas Dry Mill in 2022 with dry DGs; 0% pastureland replaced	−34	−19
Corn Ethanol Natural Gas Dry Mill in 2022 with dry DGs; 100% pastureland replaced	−2	+24
Corn Ethanol Natural Gas Dry Mill in 2022 with dry DGs; grassland only conversion and 0% pastureland replaced	−48	−38

DRIA Chapter 2 includes results for additional sensitivity analysis of corn ethanol lifecycle GHG emissions. We also intend to conduct additional sensitivity analysis for the final rule. We invite comment on these assumptions.

b. Imported Ethanol

Table VI.C.1–6 presents the breakout of lifecycle GHG emissions for sugarcane ethanol compared to a 2005 petroleum baseline under different discount rate and time horizon scenarios and land use assumptions. This assessment was based on applying the same methodology as for other biofuels including the assessment of both direct and indirect impacts using the combination of FASOM, FAPRI and Winrock modeling results. Virtually all the ethanol from sugarcane is expected to be imported from Brazilian production. Applying the proposed FAPRI/Winrock methodology to sugarcane ethanol production in Brazil predicts a large increase in new acres planted, which has a relatively large impact on overall GHG emissions. The impact is from both new sugarcane production acres in Brazil resulting in land use change but also reduced commodity exports from Brazil resulting in land use change in other countries.

The proposed FAPRI/Winrock methodology predicts that new crop acreage is converted from a range of land types. In contrast, some studies suggest that sugarcane ethanol production can increase in Brazil by relying on existing excess pasture lands and will not significantly impact other land types.[314] Table VI.C.1–6 provides the range of lifecycle GHG emission reduction results under these different assumptions of type conversion patterns. As a sensitivity analysis, shows results for a scenario where none of the grassland converted to cropland in Brazil would be replaced if, for example, livestock production could be more intensively developed on the remaining pasture (see second row in Table VI.C.1–6). The third row of Table VI.C.1–6 includes lifecycle GHG results assuming that in Brazil all of the land converted to cropland would come from grassland and that none of that grassland would be replaced. As can be seen in the table, the assumption of pastureland replacement can have an important effect on the results. DRIA Chapter 2 includes more details about the treatment of pasture conversion, and sensitivity analysis of the types land use changes induced by sugarcane ethanol production.

TABLE VI.C.1–6—SUGARCANE ETHANOL GHG EMISSION CHANGES UNDER VARIED LAND USE ASSUMPTIONS AND VARIED DISCOUNT RATES AND TIME HORIZONS RELATIVE TO 2005 PETROLEUM BASELINE

Land Use Change Scenario Description	(100 yr 2%)	(30 yr 0%)
FAPRI/Winrock estimate with managed pasture replacement	−44	−26
FAPRI/Winrock estimate with no pasture replacement in Brazil	−59	−45
Only grassland conversion in Brazil and no pasture replacement in Brazil	−64	−52

We are aware that recent land use enforcement policies in Brazil may shift cropland expansion patterns (*see* also Section VI.B.5.b.iii). We seek comment on both pasture conversion patterns and Brazil land use enforcement policy impacts. We are conducting more detailed economic modeling of the Brazilian agricultural sector by state for inclusion in FAPRI to address pasture, enforcement and other assumptions for the final rule. State level production data could be used in conjunction with Winrock's state level satellite data, which may substantially change the

[314] Goldemberg, J.; Coelho, ST.; Guardabassi, PM. The sustainability of ethanol production from sugarcane. *Energy Policy*. 2008. doi:10.1016/j.enpol.2008.02.028.

estimates of the location and type of land being converted in Brazil for the final rule.

We have also assumed that sugarcane ethanol production relies on burning bagasse as an energy source and that the process produces excess electricity. We factor in credits from this excess electricity based on offsetting the Brazilian electricity grid. As Brazil implements limits on field burning of bagasse there may be additional bagasse used at sugarcane ethanol plants and additional electricity production. We plan to look at this further for the final rule analysis.

c. Cellulosic Ethanol

Given that commercially-viable cellulosic ethanol production is not yet a reality, analysis of this pathway relies upon significant assumptions regarding the development of production technologies. As described in the previous section, our analysis assumed corn stover required no international land use changes, since corn stover does not compete with other crops for acreage in the U.S. Therefore, using corn stover as a feedstock for cellulosic biofuel production would not have an impact on U.S. exports. We assumed some of the nutrients would have to be replaced through higher fertilizer rates on acres where stover is removed; however, increased stover removal was also associated with higher rates of reduced tillage or no tillage practices which results in soil carbon increase. See Section IX.A for details. In addition, cellulosic ethanol was assumed to be produced using the biochemical process which is expected to produce more electricity from the lignin in the feedstock than is required to power the ethanol plant, so excess electricity can be sold back to the grid. See DRIA Chapter 2 for additional details. This electricity provides a GHG benefit, which results in GHG emissions reductions from fuel production as shown in Table VI.C.1–7.

TABLE VI.C.1–7—ABSOLUTE LIFECYCLE GHG EMISSIONS FOR CORN STOVER CELLULOSIC ETHANOL AND THE 2005 PETROLEUM BASELINE

[CO_2-eq/mmBtu]

	2005 Petroleum baseline	Corn stover ethanol (selling excess electricity to grid)	2005 Petroleum baseline	Corn stover ethanol (selling excess electricity to grid)
Lifecycle Stage	(100 yr 2%)		(30 yr 0%)	
Net Domestic Agriculture (w/o land use change)		178,862	N/A	124,503
Net International Agriculture (w/o land use change)		0	N/A	
Domestic Land Use Change		−78,448	N/A	−91,925
International Land Use Change		0	N/A	0
Fuel Production	823,262	−875,424	573,058	−609,367
Fuel and Feedstock Transport		107,214		74,629
Tailpipe Emissions	3,417,311	37,927	2,378,800	26,400
Net Total Emissions	4,240,674	−629,870	2,951,858	−475,130

Although switchgrass must compete with other crops for land in the U.S., average switchgrass ethanol yields are on average higher than corn ethanol yields (approximately 580 gallons/acre compared to 480 gallons/acre). Therefore, switchgrass would need approximately 20% less land to produce the same amount of ethanol compared to corn. In addition, FASOM predicts that switchgrass would generally be grown on more marginally productive land. Since switchgrass is not projected to displace crop acres with high yields, new switchgrass acres generally would not have a large impact on exports. Therefore, the international land use change impacts are modest. Like cellulosic ethanol from corn stover, switchgrass ethanol is also assumed to produce excess electricity that can be sold to the grid, therefore switchgrass cellulosic ethanol results in relatively large lifecycle GHG reductions compared to the replaced petroleum gasoline as shown in Table VI.C.1–8.

TABLE VI.C.1–8—ABSOLUTE GHG EMISSIONS FOR SWITCHGRASS CELLULOSIC ETHANOL AND THE 2005 PETROLEUM BASELINE

[CO_2-eq/mmBtu]

	2005 Petroleum baseline	Switchgrass ethanol (selling excess electricity to grid)	2005 Petroleum baseline	Switchgrass ethanol (selling excess electricity to grid)
Lifecycle Stage	(100 yr 2%)		(30 yr 0%)	
Net Domestic Agriculture (w/o land use change)		−470,620		−327,590
Net International Agriculture (w/o land use change)		−356,712		−248,301
Domestic Land Use Change		−65,318		−76,015
International Land Use Change		423,097		424,094
Fuel Production	823,262	−874,599	573,058	−608,793
Fuel and Feedstock Transport		136,663		95,129
Tailpipe Emissions	3,417,311	37,927	2,378,800	26,400

TABLE VI.C.1–8—ABSOLUTE GHG EMISSIONS FOR SWITCHGRASS CELLULOSIC ETHANOL AND THE 2005 PETROLEUM BASELINE—Continued

[CO_2-eq/mmBtu]

	2005 Petroleum baseline	Switchgrass ethanol (selling excess electricity to grid)	2005 Petroleum baseline	Switchgrass ethanol (selling excess electricity to grid)
Net Total Emissions	4,240,674	−1,169,561	2,951,858	−715,076

Cellulosic ethanol does not have nearly as significant an impact on land use as other biofuels, therefore we did not calculate sensitivity impacts of, for example, assuming full replacement of pasture versus no pasture replacement which could be important in the lifecycle GHG assessment of other biofuels. As the land use issue is not critical for the cellulosic feedstock fuels in the scenarios we analyzed, the impact of timing and discount rates also do not have a significant impact on the overall results for cellulosic ethanol. Both of the cellulosic ethanol pathways we examined, switchgrass and corn stover using enzymatic processing, reduced lifecycle GHG emissions by significantly more than the 60% threshold for cellulosic biofuel. Table VI.C.1–9 summarizes the lifecycle GHG results for cellulosic ethanol fuel pathways.

TABLE VI.C.1–9—CELLULOSIC ETHANOL GHG EMISSION CHANGES FROM DIFFERENT FEEDSTOCKS AND VARIED DISCOUNT RATES AND TIME HORIZONS RELATIVE TO 2005 PETROLEUM BASELINE

[In percent]

Assumption—feedstock type	(100 yr 2%)	(30 yr 0%)
Corn Stover	−115	−117
Switchgrass	−128	−121

d. Biodiesel

EPA's modeling predicts that soybean-based biodiesel production has a large land use impact for two major reasons. Soybean biodiesel has a relatively low gallon per acre yield (approximately 65 gal/acre for soybean biodiesel versus 480 gal/acre for corn ethanol). Thus, the impact of any land-use change tends to be magnified with soybean biodiesel. Even when the higher Btu value of biodiesel is taken into consideration, Btu/acre yields are still significantly lower for biodiesel than for ethanol (approximately 97 gal/acre ethanol equivalent). Furthermore, our analysis suggests that due to high world wide demand for soybeans for food, cooking and other non-biofuel uses, soybean and other edible oils used for biofuel are generally replaced by production in other countries including production in tropical climates where the GHG emissions released per acre of converted land are highest. This indicates that soy-based biodiesel lifecycle GHG emissions could be greatly reduced with the adoption of policies and agricultural practices that limit the amount of tropical deforestation induced by soy-based biodiesel production. DRIA Chapter 2 includes sensitivity analyses about the types of land converted to crops as a result of soy-based biodiesel production. Table VI.C.1–10 presents the breakout of the absolute lifecycle GHG emissions for soybean biodiesel and the petroleum diesel fuel baseline by lifecycle stage.

TABLE VI.C.1–10—ABSOLUTE LIFECYCLE GHG EMISSIONS FOR SOYBEAN BIODIESEL AND THE 2005 PETROLEUM BASELINE

[CO_2-eq/mmBtu]

	2005 Petroleum baseline	Soybean biodiesel	2005 Petroleum baseline	Soybean biodiesel
Lifecycle Stage	(100 yr 2%)		(30 yr 0%)	
Net Domestic Agriculture (w/o land use change)	....	−423,206	....	−294,586
Net International Agriculture (w/o land use change)	....	195,304	....	135,948
Domestic Land Use Change	....	−8,980	....	−10,451
International Land Use Change	....	2,474,074	....	2,469,574
Fuel Production	749,132	838,490	521,458	583,658
Fuel and Feedstock Transport	....	149,258	....	103,896
Tailpipe Emissions	3,424,635	30,169	2,383,828	21,000
Net Total Emissions	4,173,768	3,255,109	2,905,286	3,009,039

Our analysis is based on a change in biodiesel volumes from 0.4 Bgal to 0.7 Bgal. Similar to the analysis we conducted for corn-ethanol, we plan to run a sensitivity analysis on the impact of using different volumes for the final rule.

As discussed in Section VI.B.2.a, EPA's interpretation of the EISA statute compels us to include significant indirect emission impacts including those due to land use changes in other countries. The data in Table VI.C.1–10 indicate that excluding the international land use change would result in soy-based biodiesel having an approximately 80% reduction in lifecycle GHG emissions compared to petroleum gasoline regardless of the timing or discount rate used. The treatment of emissions over time is not critical if international land use change emissions are excluded because the results without land use change are consistent over time. Therefore the overall lifecycle GHG results do not vary with time or discount rate assumptions.

In contrast, GHG emissions from waste oil and greases are assumed to have no land use impacts. We assumed any land use change was attributed to the original use of the feedstock, for example, soy oil was produced for the purpose of using for cooking and the land required to produce this cooking oil is properly attributed to that use. Gathering and re-using the left over waste cooking oil would have no additional land use impact. This lack of land use impact greatly influences the lifecycle GHG analysis. Table VI.C.1–11 presents the breakout of the absolute lifecycle GHG emissions for waste grease biodiesel and the petroleum diesel fuel baseline by lifecycle stage.

TABLE VI.C.1–11—ABSOLUTE LIFECYCLE GHG EMISSIONS FOR WASTE GREASE BIODIESEL AND THE 2005 PETROLEUM BASELINE

[CO_2-eq/mmBtu]

	2005 Petroleum baseline	Waste grease biodiesel	2005 Petroleum baseline	Waste grease biodiesel
Lifecycle Stage	(100 yr 2%)		(30 yr 0%)	
Net Domestic Agriculture (w/o land use change)		0		0
Net International Agriculture (w/o land use change)		0		0
Domestic Land Use Change		0		0
International Land Use Change		0		0
Fuel Production	749,132	658,198	521,458	458,160
Fuel and Feedstock Transport		149,258		103,896
Tailpipe Emissions	3,424,635	30,169	2,383,828	21,000
Net Total Emissions	4,173,768	837,626	2,905,286	583,056

Table VI.C.1–12 summarizes the lifecycle GHG results for biodiesel fuel pathways. As the waste grease biodiesel is not assumed to have any land use impact the choice of timing or discount rate does not impact the waste grease biodiesel results. However, as the soybean biodiesel is found to have a large land use impact the choice of timing and discount rate has a big impact on the soybean biodiesel results.

TABLE VI.C.1–12—BIODIESEL LIFECYCLE GHG EMISSION CHANGES FROM DIFFERENT FEEDSTOCKS AND VARIED DISCOUNT RATES AND TIME HORIZONS RELATIVE TO 2005 PETROLEUM BASELINE

Assumption—feedstock type	(100 yr 2%)	(30 yr 0%)
Soybean	−22%	+4%
Waste Grease	−80%	−80%

Table VI.C.1–13 shows the sensitivity of our assessment for soy oil biodiesel assuming 100% of the grassland converted to cropland is replaced compared to an assumption that none of this grassland is replaced for livestock grazing. DRIA Section 2.8.2.4 provides more information about sensitivity analysis for the pasture replacement assumptions.

TABLE VI.C.1–13—SOY-BASED BIODIESEL GHG EMISSION CHANGES UNDER VARIED LAND USE ASSUMPTIONS AND VARIED DISCOUNT RATES AND TIME HORIZONS RELATIVE TO 2005 PETROLEUM BASELINE

Assumption—land types available for conversion	(100 yr 2%)	(30 yr 0%)
100% Pasture Replacement	−4%	+27%
No Pasture Replacement	−45%	−27%

2. Treatment of GHG Emissions Over Time

As described in Section VI.B.5, changes in indirect land use associated with increased biofuel production result in GHG emissions increases that accumulate over a long time period. Since there is a large release of carbon in the first year of land conversion, it can take many years for the benefits of the biofuel to make up for these early carbon emissions, depending on the specific biofuel in question. Table VI.C.2–1 contains the payback period associated with several types of biofuels and fuel production pathways. A payback period of 0 indicates that these pathways do not have land use change impacts and therefore reduce emissions in the first year that they are produced. Assessments are made in comparison to the baseline transportation fuel used in 2005 in the U.S. as mandated by EISA. The percent reduction goal is the lifecycle GHG emissions of the biofuel compared to the baseline petroleum fuel it is replacing.

TABLE VI.C.2–1—PAYBACK PERIOD
[in years]

Fuel type	Payback period (years)			
	Reduction goal: 0%	Reduction goal: 20%	Reduction goal: 50%	Reduction goal: 60%
Corn Ethanol 2022 Base Dry Mill NG[315]	33	54	[316] N/A	N/A
Corn Ethanol 2022 Best Case Dry Mill NG[317]	23	31	N/A	N/A
Corn Ethanol 2022 Base Dry Mill Coal[318]	75	>100	N/A	N/A
Corn Ethanol 2022 Base Dry Mill Biomass[319]	22	31	N/A	N/A
Soybean Biodiesel	32	46	105	N/A
Waste Grease Biodiesel	0	0	0	N/A
Sugarcane Ethanol	18	26	61	N/A
Switchgrass Ethanol	3	3	4	5
Corn Stover Ethanol	0	0	0	0

As described in Section VI.B.5, we have focused our lifecycle GHG analysis on two ways of accounting for GHG emissions over time. In one set of results we consider lifecycle GHG emissions over 100 years and discount future emissions with a 2% discount rate. In the other set of results we consider 30 years of GHG emissions with no discounting of future emissions (i.e., 0% discount rate). Whereas the discussion immediately above focused on lifecycle GHG impacts assuming 100 years with a 2% discount rate and 30 years with no discount rate, Table VI.C.2–2 shows the lifecycle GHG emissions reductions estimates with a variety of time periods and discount rates.

TABLE VI.C.2–2—LIFECYCLE GHG EMISSIONS CHANGES OF SELECT BIOFUELS RELATIVE TO THE 2005 PETROLEUM BASELINE

	Lifecycle GHG emissions changes of select biofuels relative to the 2005 petroleum baseline											
Time horizon	30 Years				50 Years				100 Years			
Discount rate	0%	2%	3%	7%	0%	2%	3%	7%	0%	2%	3%	7%
Corn Ethanol Dry Mill NG	5%	18%	25%	54%	−17%	−2%	7%	44%	−36%	−16%	−4%	41%
Corn Ethanol Best Case Dry Mill NG	−14%	−1%	6%	35%	−36%	−21%	−12%	25%	−55%	−35%	−23%	22%
Corn Ethanol Dry Mill Coal	34%	46%	53%	83%	11%	27%	35%	72%	−8%	13%	24%	69%
Corn Ethanol Dry Mill Biomass	−18%	−6%	1%	31%	−41%	−25%	−17%	20%	−60%	−39%	−28%	16%
Soybean Biodiesel	4%	20%	29%	68%	−24%	−4%	7%	55%	−48%	−22%	−7%	51%
Waste Grease Biodiesel	−80%	−80%	−80%	−80%	−80%	−80%	−80%	−80%	−80%	−80%	−80%	−80%
Sugarcane Ethanol	−27%	−17%	−11%	12%	−45%	−32%	−26%	3%	−61%	−44%	−35%	1%
Switchgrass Ethanol	−124%	−122%	−121%	−115%	−128%	−125%	−124%	−117%	−131%	−128%	−126%	−117%
Corn Stover Ethanol	−116%	−117%	−117%	−118%	−115%	−116%	−116%	−117%	−114%	−115%	−115%	−117%

D. Thresholds

EISA established GHG thresholds for each category of renewable fuel that it mandates. EISA also provided EPA with the authority to adjust the threshold levels for each category of renewable fuels if certain requirements are met. Renewable fuels must achieve a 20% reduction in lifecycle greenhouse gas emissions compared to the average lifecycle greenhouse gas emissions for gasoline or diesel sold or distributed as transportation fuel in 2005. Due to the grandfathering provisions of EISA as adopted in this rule, this threshold only pertains to renewable fuel produced at plants to be constructed in the future. EPA is permitted to adjust this threshold to as low as 10%, based on the ''maximum achievable level, taking cost into consideration, for natural gas fired corn-based ethanol plants allowing for the use of a variety of technologies.'' Based on our analysis, there are a number of corn ethanol natural gas plant configurations that could meet the 20% reduction in GHG emissions thresholds in 2022 if modeling emission over a 100 year time frame and then discounting these emissions 2%. Therefore, based on this assessment, we believe that an adjustment to the 20% threshold would be unnecessary and we are proposing to maintain it at the 20% level if we adopt the 100 year, 2% discounting methodology.

On the other hand, based on our current analyses, if we adopt an assessment methodology which assesses emissions over just 30 years, then no currently analyzed natural gas-fired corn ethanol pathway will meet the 20% threshold. However, some of the natural gas corn ethanol pathways do

[315] Dry Mill corn ethanol plant using natural gas with 2022 energy use and dry DDGS.

[316] Payback periods were not calculated for ethanol made from corn starch for the advanced biofuel reduction goals of 50% and 60% since this corn ethanol does not qualify under EISA as a potential advanced biofuel.

[317] Dry Mill corn ethanol plant using natural gas with 2022 energy use and w/CHP, Fractionation, Membrane Separation, and Raw Starch Hydrolysis (wet DGS).

[318] Dry Mill corn ethanol plant using coal with 2022 energy use and dry DDGS.

[319] Dry Mill corn ethanol plant using biomass with 2022 energy use and dry DDGS.

have lifecycle GHG emission benefits in the 10% to 20% range. Corn ethanol is expected to be the major biofuel contributing to meeting the renewable fuel standards through at least the middle of the next decade. Therefore, if we adopt a 30 year timeframe for emissions assessment and do not discount the results, we may adjust the renewable fuel thresholds to the minimum level as necessary to incorporate at least a few of the best GHG pathways for corn ethanol. While this adjusted threshold level could be revised based on pathway analyses done for the final rule, at this time we would intend to allow a full 10% adjustment of the renewable fuel threshold, down to a threshold value of 10% reduction compared to the 2005 gasoline baseline.

Cellulosic biofuels must meet a 60% reduction in GHG emissions relative to the petroleum baseline. EPA is permitted to adjust this threshold to as low as 50% if it is ''not commercially feasible for fuels made using a variety of feedstocks, technologies, and processes'' to achieve the 60% threshold. Our initial analysis indicates that cellulosic biofuels from corn stover, switchgrass, and bagasse will all meet the 60% threshold regardless of whether we use to 100 year, 2% discount methodology or the 30 year analysis time frame without discounting. Furthermore, we believe most fuels made from other cellulosic feedstocks would as well. Therefore we do not believe it is necessary to adjust the threshold for cellulosic biofuel at this time.

Biomass-based diesel must achieve a 50% reduction in GHG emissions relative to petroleum-based diesel. EPA is permitted to adjust this threshold to as low as 40% if it is ''not commercially feasible for fuels made using a variety of feedstocks, technologies, and processes'' to meet the 50% level. For biomass-based diesel, our analysis indicates that biodiesel from waste oils such as yellow grease and tallow would meet the 50% threshold, and we anticipate that biodiesel from chicken waste and non-food grade corn oil fractionation would as well regardless of whether we use a 100 year, 2% discount methodology or the 30 year analysis time frame without discounting. However, our current analysis indicates that there is insufficient feedstock from waste grease and fats to meet the one billion gallon volumetric requirement under EISA. Biodiesel from soy oil (and we believe biodiesel from other food grade vegetable oils) would reduce GHG emissions by no more than 22% using a 100 year, 2% discount methodology and would be estimated to increase GHG emissions if we analyze emission impacts over 30 years whether the emissions are discounted or not. Even if EPA adjusted the biomass-based diesel standard to the minimum allowable level of 40%, soybean-based biodiesel would still not meet the GHG emissions reductions threshold for biomass based diesel fuel. One option for meeting the volumetric requirement and the emissions reduction threshold, assuming a 100 year timeframe and a 2% discount rate for GHG emission impacts would be to allow biodiesel producers to average the emissions reductions from a blend of soy oil or food grade vegetable oil-based biodiesel with waste oil based biodiesel, as discussed in more detail in Section VI.E. However, this approach may still be insufficient to ensure that the required volumes of biomass-based diesel can be produced unless other sources of biomass-based diesel become available. Therefore, we invite comments on whether it be appropriate to both reduce the threshold to 40% and allow biodiesel producers to average their emissions to meet the one billion gallon volumetric requirement as discussed below in Section VI.E.3.c.

Advanced biofuels must achieve a 50% reduction in GHG emissions. EPA is permitted to adjust this threshold to as low as 40% if it is ''not commercially feasible for fuels made using a variety of feedstocks, technologies, and processes'' to achieve the 50% threshold. Our current lifecycle analysis suggests that sugarcane based ethanol only offers an estimated 44% reduction in GHG emissions relative to the gasoline it replaces when assessing 100 years of emission impacts and discounting these emissions 2%, and an estimated 27% reduction when assessing 30 years of emission impacts with no discounting. Therefore, it would not qualify as an advanced biofuel if we did not adjust the 50% GHG threshold. We are also unaware of other renewable fuels that may be available in sufficient volumes over the next several years to allow the statutory volume requirements for advanced biofuel to be met. As a result, we are proposing that the GHG threshold for advanced biofuels be adjusted to 44% or potentially as low as 40% depending on the results from the analyses that will be conducted for the final rule. Based on our current analysis of the lifecycle GHG impacts of sugarcane ethanol, such an adjustment would help ensure that the volume mandates for advanced biofuel can be met.

We invite comments on these proposed thresholds and our basis for them.

E. Assignment of Pathways to Renewable Fuel Categories

The lifecycle analyses that we conducted for a variety of fuel pathways formed the basis for our determination of which pathways would be permitted to generate RINs, and to which of the four renewable fuel categories (cellulosic biofuel, biomass-based diesel, advanced biofuel, and renewable fuel) those RINs should be assigned. This determination involved comparing the lifecycle GHG performance estimates to the GHG thresholds associated with each renewable fuel category, discussed in Section VI.D above. In addition, each of the four renewable fuel categories is defined in EISA to include or exclude certain types of feedstocks and production processes, and these definitions also played a role in determining the appropriate category for each pathway. This section describes our proposed assignments of pathways to one of the four renewable fuel categories. The GHG lifecycle values used in this assignment of fuel pathways to the four renewable fuel categories were based on the lifecycle analysis results over a 100-year timeframe and using a 2% discount rate, as described in Section VI.C. Different assignments of pathways to the four renewable fuel categories would occur with different lifecycle results, but we propose that the same assignment methodology would be followed regardless.

1. Statutory Requirements

EISA establishes requirements that are common to all four categories of renewable fuel in addition to requirements that are unique to each of the four categories. The common requirements determine which fuels are valid for generating RINs under the RFS2 program. For instance, all renewable fuel must be made from renewable biomass, which defines the types of feedstocks that can be used to produce renewable fuel that is valid under the RFS2 program, and also defines the types of land on which crops can be grown if those crops are used to produce valid renewable fuel under the RFS2 program. See Section III.B.4 for a more detailed discussion of renewable biomass. Moreover, all renewable fuel must displace fossil fuel present in transportation fuel, or be used as home heating oil or jet fuel.

The requirements that are unique to each of the four categories provide a basis for assigning each pathway to a category. For each of the four categories of renewable fuel, EISA provides a definition, specifies the associated GHG thresholds, lists the allowable feedstocks and/or fuel types, and in some cases provides exclusions. Table VI.E.1–1 summarizes these requirements as we are applying them under the proposed RFS2 program.

TABLE VI.E.1–1—REQUIREMENTS FOR RENEWABLE FUEL CATEGORIES

	Cellulosic biofuel	Biomass-based diesel	Advanced biofuel	Renewable fuel
GHG threshold	60%	50% [a]	40–44% [a]	20% [a, b].
Eligible Inclusions	Renewable fuel made from cellulose, hemicellulose, or lignin.	Any renewable fuel that is a diesel fuel substitute.	All cellulosic biofuel and biomass-based diesel, as well as other renewable fuels including ethanol from sugar, starch, or waste materials, biogas, and butanol and other alcohols.	All advanced biofuel, and any other fuel made from renewable biomass that is used to replace or reduce the quantity of fossil fuel present in a transportation fuel.
Exclusions		Any renewable fuel made from coprocessing with petroleum.	Ethanol derived from corn starch.	

[a] As discussed in Section VI.D, we are seeking comment on the need to adjust the thresholds, and are proposing that the GHG threshold for advanced biofuels be adjusted to as low as 40%.

[b] 20% threshold does not apply to grandfathered volumes. *See* discussion in Section III.B.3.

2. Assignments for Pathways Subjected to Lifecycle Analyses

There are a wide variety of pathways (unique combinations of feedstock, fuel type, and fuel production process) that could result in renewable fuel that would be valid under the RFS2 program. As described earlier in this section, we conducted lifecycle analyses for some of these pathways, and these analyses allowed us to determine if the GHG thresholds shown in Table VI.E.1–1 would be met under the assumption of a 100-year timeframe and discount rate of 2%. For other pathways that we have not yet subjected to lifecycle analyses, there were some cases in which we could nevertheless still make moderately confident determinations as to the likely GHG impacts by making comparisons to the pathways that we did analyze. A discussion of these other determinations is provided in Section VI.E.3 below.

For pathways that we subjected to lifecycle analysis, we were able to assign each pathway to one of the four renewable fuel categories defined in EISA by comparing the descriptions of each pathway and its associated GHG performance to the requirements shown in Table VI.E.1–1. The results are shown in Table VI.E.2–1.

TABLE VI.E.2–1—PROPOSED ASSIGNMENT OF PATHWAYS TO ONE OF THE FOUR RENEWABLE FUEL CATEGORIES FOR PATHWAYS SUBJECTED TO LIFECYCLE ANALYSES

Cellulosic biofuel pathways	Ethanol produced from corn stover or switchgrass in a process that uses enzymes to hydrolyze the cellulose and hemicellulose.
Biomass-based diesel pathways	Biodiesel (mono alkyl esters) produced from waste grease and waste oils.
Advanced biofuel pathways	Ethanol produced from sugarcane sugar in a process that uses sugarcane bagasse for process heat. [a]
Renewable fuel pathways	Ethanol produced from corn starch in a process that uses biomass for process heat.
	Ethanol produced from corn starch in a process that includes: —Dry mill plant. —Process heat derived from natural gas. —Combined heat and power (CHP). —Fractionation of feedstocks. —All distillers grains are dried.
	Ethanol produced from corn starch in a process that includes: —Dry mill plant. —Process heat derived from natural gas. —All distillers grains are wet.
	Ethanol produced from corn starch in a process that includes: —Dry mill plant. —Process heat derived from coal. —Combined heat and power (CHP). —Fractionation of feedstocks. —Membrane separation of ethanol. —Raw starch hydrolysis. —All distillers grains are dried.
	Ethanol produced from corn starch in a process that includes: —Dry mill plant. —Process heat derived from coal. —Combined heat and power (CHP). —Fractionation of feedstocks. —Membrane separation of ethanol. —All distillers grains are wet.

TABLE VI.E.2–1—PROPOSED ASSIGNMENT OF PATHWAYS TO ONE OF THE FOUR RENEWABLE FUEL CATEGORIES FOR PATHWAYS SUBJECTED TO LIFECYCLE ANALYSES—Continued

	Biodiesel (mono alkyl esters) produced from soybean oil.

[a] Our current analysis concludes that ethanol from sugarcane sugar would have a GHG performance of 44% in comparison to gasoline under our assumed 100-year timeframe and 2% discount rate. Since this falls short of the 50% GHG threshold for advanced biofuel, we have categorized it as general renewable fuel. However, we request comment on lowering the applicable GHG threshold for advanced biofuel so that ethanol from sugarcane sugar could be categorized as advanced biofuel. See further discussion in Section VI.D.

In addition, our lifecycle analyses also identified pathways that did not meet the minimum 20% GHG threshold under an assumed 100-year timeframe and 2% discount rate, and thus would be prohibited from generating RINs unless a facility met the prerequisites for grandfathering as described in Section III.B.3. These prohibited pathways all involved the production of ethanol from corn starch in a process that uses natural gas or coal for process heat, but which does not meet any of the process technology requirements listed in Table VI.E.2–1. Our proposal for temporary D codes in § 80.1416 would explicitly prohibit the generation of RINs for these pathways.

The proposed assignments of individual pathways to one of the four renewable fuel categories shown in the table above assumed a 100-year timeframe and discount rate of 2% for lifecycle GHG emission impacts. The assignments would be different if we had assumed a different timeframe and discount rate. By comparing the relative GHG emission reductions shown in Table VI.C.1–2 to the thresholds in Table VI.E.1–1, a variety of different assignments is possible covering timeframes of 30, 50, and 100 years, and discount rates of 0%, 2%, 3%, and 7%. For instance, under the assumption of 30 years and no discounting, switchgrass ethanol and corn stover ethanol would continue to be categorized as cellulosic biofuel and biodiesel made from waste grease would continue to be categorized as biomass-based diesel. However, sugarcane ethanol could no longer be potentially categorized as advanced biofuel but instead would be categorized as renewable fuel. Moreover, some pathways would not meet the minimum threshold of 20% for renewable fuel, and so could not generate RINs if the volume was not grandfathered. This would include soybean biodiesel and all of the corn starch ethanol pathways shown in Table VI.E.2–1 produced from newly constructed plants not meeting the grandfathering criteria discussed in Section III.B.3.

3. Assignments for Additional Pathways

We were not able to conduct lifecycle modeling for all potential pathways in time for this proposed rulemaking. Instead, we focused the lifecycle GHG emissions analysis on the feedstocks that, based on FASOM predictions and other information, we anticipate could contribute the largest volumes to the renewable fuel pool and the production processes representing the largest shares of the market. As more information becomes available, we anticipate that we will be updating the lifecycle methodology and expanding the list of emission factors.

Beyond the pathways that we explicitly subjected to lifecycle analysis, there are additional pathways that may not currently be significant contributors to the volume of renewable fuel produced, but their volumes could increase in the future. Moreover, we believe it is important that as many pathways as possible be included in the lookup table in the regulations to help ensure that the volume requirements in EISA can be met and to encourage the development of new fuels. To this end, we evaluated these additional pathways to determine if they could be deemed valid for generation of RINs, and if so which of the four renewable fuel categories they would fall into. This section describes our evaluation of these additional pathways and the resulting proposed assignment to one or more of the four renewable fuel categories.

a. Ethanol From Starch

Our lifecycle analysis focused on ethanol from corn starch. However, there are a variety of other sources of starch that use or could use a very similar process for conversion to ethanol. These include wheat, barley, oats, rice, and sorghum. Some existing corn-ethanol facilities already use small amounts of starch from these other plants along with corn in their production of ethanol.

Although we have not explicitly analyzed the land use or processing impacts of these other starch plants on their lifecycle GHG performance, we believe it would be reasonable to assume similar impacts to corn in terms of the types of land that would be displaced and other aspects of producing and transporting the feedstock. Therefore, we propose that the pathways shown in Table VI.E.2–1 for ethanol produced from corn starch also be applied to ethanol produced from other sources of starch.

The lifecycle analyses conducted for this proposal only examined cases in which a corn-ethanol facility dried 100% of its distiller's grains or left 100% of its distiller's grains wet. The treatment of the distiller's grains for corn-ethanol facilities impacts the determination of whether the 20% GHG threshold for renewable fuel has been met. However, in practice some facilities may dry only a portion of their distiller's grains and leave the remainder wet. As described in Section III.D.3, we are proposing that a facility that dried only a portion of its distiller's grain would be treated as if it dried 100% of its grains, and would thus need to implement additional GHG-reducing technologies as described in the lookup table in order to qualify to generate RINs. However, we are also taking comment on whether a selection of pathways should be included in the lookup table that represent corn-ethanol facilities that dry only a portion of their distiller's grains. We also request comment on whether RINs could be assigned to only a portion of the facility's ethanol in cases wherein only a portion of the distiller's grains are dried.

b. Renewable Fuels from Cellulosic Biomass

In analyzing the lifecycle GHG impacts of cellulosic ethanol, we determined that ethanol produced from corn stover or switchgrass through a process using enzymatic hydrolysis followed by fermentation of the resulting sugars met the GHG threshold of 60% for cellulosic biofuel by a wide margin (regardless of the discount rate and the time period over which the lifecycle GHG emissions are discounted). However, there are many other potential sources of cellulosic biomass, and other processing mechanisms to convert cellulosic biomass into fuel. For some of these cases, we believe that we can make determinations regarding whether the GHG thresholds shown in Table VI.E.1–1 are likely to be met. In addition, as the forestry component of the FASOM model is incorporated into the analysis, we will analyze pathways using planted trees, tree residue, and slash and pre-commercial thinnings from forestland, as qualify under the renewable biomass definition, for feedstock.

Cellulosic biomass sources include waste biomass such as corn stover, and crops grown specifically for fuel production such as switchgrass. While cellulosic crops grown for the purpose of fuel production could have land use implications in a lifecycle GHG analysis, waste materials produced during the harvesting of some other type of crop would not. Given that the GHG impacts of a fermentation-based fuel production process are likely to be very similar for cellulose from a variety of feedstocks, we believe it would be reasonable to conclude that any cellulosic feedstock from a waste source that is subjected to enzymatic hydrolysis followed by fermentation of the resulting sugars would be very likely to meet the 60% GHG threshold for cellulosic biofuel. Therefore, we propose that cellulosic ethanol produced through an enzymatic hydrolysis process followed by fermentation using any eligible waste cellulosic feedstock would be determined to meet the 60% GHG threshold for cellulosic biofuel. This would include such wastes as wheat straw, rice straw, sugarcane bagasse, forest slash and thinnings, and yard waste.

As stated earlier, cellulosic crops grown for the purpose of fuel production could have land use implications in a lifecycle GHG analysis. However, the only cellulosic crop that we subjected to lifecycle analysis was switchgrass which had a relatively small impact of land-use. Other cellulosic crops that have been considered for fuel production include miscanthus and trees such as poplar and willow. It is possible that the land use impacts of miscanthus and planted trees could be different from that for switchgrass. For instance, while switchgrass can be grown on marginal lands, planted trees may require more arable land to thrive. However, according to our lifecycle analysis for switchgrass, the land use impacts could significantly increase and the 60% threshold for cellulosic biofuel would still be met. Therefore, we propose that the pathways shown in Table VI.E.2–1 for ethanol produced from switchgrass through an enzymatic hydrolysis process followed by fermentation also be applied to ethanol produced from miscanthus and planted trees. We intend to examine this pathway more closely for the final rule to determine if this categorization is appropriate, and request comment on the land use impacts of miscanthus and planted trees.

Renewable fuels can also be produced from cellulosic biomass through various thermochemical processes rather than enzymatic hydrolysis followed by fermentation. One example of such thermochemical processes would be biomass gasification to produce ‘‘syngas’’ (a mixture of hydrogen and carbon monoxide) which is then catalytically synthesized through a Fischer-Tropsch process to produce ethanol, diesel, gasoline, or other transportation fuels. Another example would be a catalytic depolymerization process in which the biomass is first catalytically cracked to smaller molecules and then polymerized under specific combinations of temperature, pressure, and residence time to produce a transportation fuel. We have not conducted a lifecycle analysis of these pathways, but we believe that we can nonetheless make a reasonable determination regarding the appropriate renewable fuel category. For instance, we would expect that the GHG emissions produced during fuel production would be higher for a thermochemical process than for enzymatic hydrolysis due to the need for greater process heat produced through the combustion of fossil fuels. However, the yield of fuel produced per ton of biomass is likely to be greater for thermochemical processing due to the conversion of the lignin to fuel in addition to the cellulose and hemicellulose. Thus, while the lifecycle GHG analyses we conducted for corn stover and switchgrass demonstrated that the 60% GHG threshold for cellulosic biofuel would be met by a wide margin, this margin may be smaller if a thermochemical process was used. While we intend to conduct further analyses of this family of pathways for the final rule, we believe that a change from enzymatic hydrolysis to a thermochemical process would be expected to meet the 60% GHG threshold associated with cellulosic biofuel. Therefore, we propose that the use of corn stover or other waste cellulosic biomass, switchgrass, or planted trees in a thermochemical process would qualify as cellulosic biofuel under the RFS2 program. This would include pathways that produce ethanol, cellulosic diesel, or cellulosic gasoline. Since cellulosic diesel fuel produced in this way would also meet the requirements for biomass-based diesel, we propose to allow it to be categorized as either cellulosic biofuel or biomass-based diesel at the producer's discretion. See further discussion of this issue in Section III.D.2.a. We request comment on our proposed assignment of categories for renewable fuels produced through a thermochemical process, as well as data and other information relating to the various types of thermochemical fuel production processes.

c. Biodiesel

Our lifecycle analysis of biodiesel (mono alkyl esters) produced from waste greases/oils demonstrated that the 50% GHG threshold for biomass-based diesel would be met. Much of the GHG benefit of these waste greases/oils derives from the fact that they have no land use impacts. While we did not subject corn oil that is non-food grade to lifecycle analysis, it is likely that it would also have no land use impacts. Moreover, such non-food grade corn oil would require nearly the same process energy to convert it into biodiesel. Therefore, we propose that the pathway shown in Table VI.E.2–1 for biodiesel produced from waste greases/oils also be applied to biodiesel produced from non-food grade corn oil. We intend to analyze this pathway in more depth for the final rule.

Our lifecycle analysis of biodiesel produced from soybean oil may also be applicable to biodiesel produced from other types of virgin (not waste) oils. This would include canola oil, rapeseed oil, sunflower oil, and peanut oil. While we have not conducted a detailed assessment of the land use impacts of these other virgin oils, it is possible that they would meet the 20% threshold for generic renewable fuel. Therefore, we propose that the pathway shown in Table VI.E.2–1 for biodiesel produced from soybean oil also be applied to biodiesel produced from other these virgin oils. We request comment on whether this is appropriate.

Although our proposed list of RIN-generating pathways would allow biodiesel made from waste greases/oils to qualify as biomass-based diesel, it is likely that there would be insufficient quantities of these feedstocks to reach the 1.0 billion gallon requirement by 2012. Biodiesel produced from soybean oil would not qualify as biomass-based diesel, but instead would be categorized as generic renewable fuel based on our current analysis of its lifecycle GHG performance. However, biodiesel production facilities can process either soybean oil or waste grease with relatively minor changes in operations, and many facilities that formerly used soybean oil have recently switched to waste grease due to its more favorable economics. Since the GHG performance of biodiesel made from waste greases/oils met the 50% GHG threshold by a wide margin, and since it is common industry practice for biodiesel facilities to use these two feedstock sources, we believe it may be appropriate to allow a biodiesel production facility to average the GHG benefit generated through the use of waste grease with the lower GHG performance of biodiesel produced from soybean oil at the same facility.

We recognize that an approach in which we allow a biodiesel production facility to average the GHG benefit of waste grease with that from soybean oil raises questions about whether similar averaging could be allowed for other combinations of feedstocks, other types of fuel, or across multiple facilities within the same company. While we believe that the circumstances surrounding biodiesel production are somewhat unique—two different feedstocks subjected to essentially the same production process in a single facility—we nevertheless request comment on the appropriateness of such an averaging approach for biodiesel.

Based on our lifecycle analyses, biodiesel produced from waste grease has a GHG performance of 80% reduction from the conventional diesel baseline, while biodiesel produced from soybean oil has a GHG performance of 22% reduction. In order to meet the GHG threshold of 50% for biomass-based diesel, a biodiesel production facility would need to use a minimum of 48% waste grease and a maximum of 52% soybean oil. Thus, a pathway that would allow a biodiesel production facility to designate all of its biodiesel as biomass-based diesel would include a requirement that the producer demonstrate that every batch has been produced from no less than 48% waste grease and no more than 52% soybean oil.

Although this approach would allow the total volume of biomass-based diesel to be larger than if waste greases/oils alone qualified, it is still possible than the 1.0 billion gallon requirement would not be met due to limits on the availability of waste greases and oils. For instance, we estimate that the total volume of waste greases and oils may be no larger than 0.3–0.4 billion gallons. As a result, we request comment on whether it would also be appropriate to lower the GHG threshold for biomass-based diesel. If this GHG threshold were lowered to 40%, a biodiesel production facility would only need to use a minimum of 31% waste greases/oils instead of 48%.

We recognize that it may be difficult for a biodiesel production facility to process a consistent mixture of waste grease and soybean oil every day. Therefore, we request comment on alternative approaches. For instance, if a biodiesel production facility processed only waste grease for the first 175 days (48% × 365 days) of a calendar year, we could allow it to designate any biodiesel produced from soybean oil for the remainder of the year as biomass-based diesel. However, this may be difficult for some producers who must contend with cold temperature storage and blending issues in the early part of a calendar year by processing only soybean oil. Alternatively, we could allow a company to average the production at all of its facilities, where one facility processed only waste grease and another processed only soybean oil.

Finally, we request comment on an alternative approach in which an obligated party, rather than the biodiesel production facility, would demonstrate that a minimum number of waste grease-based biodiesel RINs is used to meet the biomass-based diesel standard in comparison to the number of soybean oil-based biodiesel RINs. In essence, the averaging would be carried out by the obligated party instead of the biodiesel producer. In this approach, biodiesel RINs would not be placed into biomass-based diesel category shown in Table VI.E.1–1, but instead would be placed into two separate categories as waste grease RINs or soybean oil RINs. This designation would require that the list of applicable D codes for use in the RIN be expanded from four to six as shown in Table VI.E.3.c–1.

TABLE VI.E.3.C–1—ALTERNATIVE APPROACH TO D CODES FOR AVERAGING WASTE GREASE AND SOYBEAN OIL BIODIESEL RINS IN COMPLIANCE

D value	Proposal meaning	Alternative approach meaning
1	Cellulosic biofuel	Cellulosic biofuel
2	Biomass-based diesel.	Biomass-based diesel
3	Advanced biofuel	Biodiesel made from soybean oil
4	Renewable fuel ...	Biodiesel made from waste grease
5	(Not applicable) ..	Advanced biofuel
6	(Not applicable) ..	Renewable fuel

Since other types of renewable fuel may still qualify as biomass-based diesel, we would retain a separate D code for this category under this approach. This could allow biodiesel producers who choose the process a minimum of 48% waste greases/oils each day to continue to assign a D code of 2 to their biodiesel.

An obligated party could use any combination of RINs with a D code of 2, 3, or 4 in order to comply with the biomass-based diesel standard. However, he would also be subject to an additional requirement that the ratio of D=3 RINs to D=4 RINs must be less than 1.08. This criterion would ensure that a minimum of 47 RINs representing biodiesel from waste grease would be used for compliance purposes for every 53 RINs representing biodiesel from soybean oil that are also used for compliance.

We request comment on these alternative approaches to the treatment of biodiesel.

d. Renewable Diesel Through Hydrotreating

We did not conduct a lifecycle analysis for the production of non-ester renewable diesel through a hydrotreating process. However, we believe that our analysis of biodiesel provides sufficient information to allow us to designate the renewable fuel category for various pathways leading to the production of renewable diesel.

Renewable diesel is generally made from the same feedstocks as biodiesel, namely soybean oil, waste greases/oils, tallow, and chicken fat. Therefore, the GHG impacts associated with producing/collecting the feedstock and transporting it to the production facility would be the same regardless of whether the final product is biodiesel or renewable diesel.

The fossil energy requirements of the production process contribute a relatively small amount to the overall GHG performance for biodiesel. For example, the 50% GHG threshold would still be met for biodiesel produced from waste grease even if the fossil energy requirements doubled. As a result, compared to the transesterification process used to produce biodiesel, any small variations in fossil energy requirements for renewable diesel production in a hydrotreater would be unlikely to change compliance with the broad categories created by the GHG thresholds for biomass-based diesel and generic renewable fuel. Therefore, we believe that it would be appropriate to assign applicable renewable fuel categories to renewable diesel pathways in parallel with the assignments we are proposing for biodiesel, including the potential for averaging of soyoil and waste grease derived volumes. Renewable diesel produced from waste grease, tallow, or chicken fat in a hydrotreater that does not coprocess petroleum feedstocks would be categorized as biomass-based diesel. Renewable diesel produced from waste grease, tallow, or chicken fat in a hydrotreater that does coprocess petroleum feedstocks would be categorized as advanced biofuel. Finally, renewable diesel produced from soybean oil in a hydrotreater would be categorized as generic renewable fuel.

4. Summary

Based on the discussion above, we have identified 15 pathways that we propose could be used to produce fuel that would meet the volume requirements in EISA assuming a 100 year analysis time frame and discounting GHG emissions over time by 2%. As noted above, these pathways would be adjusted should we adopt other time frames or discount rates (including a zero discount rate) for the final rule. Each pathway would be assigned a D code for use in generating RINs that corresponds to one of the four renewable fuel categories. Our proposed list of allowable pathways is shown in Table VI.E.4–1.

TABLE VI.E.4–1—APPLICABLE CATEGORIES FOR EACH FUEL PATHWAY [a]

Fuel type	Feedstock	Production process requirements	Category
Ethanol	Starch from corn, wheat, barley, oats, rice, or sorghum.	—Process heat derived from biomass.	Renewable fuel.
Ethanol	Starch from corn, wheat, barley, oats, rice, or sorghum.	—Dry mill plant —Process heat derived from natural gas. —Combined heat and power (CHP). —Fractionation of feedstocks. —Some or all distillers grains are dried.	Renewable fuel.
Ethanol	Starch from corn, wheat, barley, oats, rice, or sorghum.	—Dry mill plant —Process heat derived from natural gas. —All distillers grains are wet.	Renewable fuel.
Ethanol	Starch from corn, wheat, barley, oats, rice, or sorghum.	—Dry mill plant —Process heat derived from coal. —Combined heat and power (CHP). —Fractionation of feedstocks. —Membrane separation of ethanol. —Raw starch hydrolysis. —Some or all distillers grains are dried.	Renewable fuel.
Ethanol	Starch from corn, wheat, barley, oats, rice, or sorghum.	—Dry mill plant —Process heat derived from coal. —Combined heat and power (CHP). —Fractionation of feedstocks. —Membrane separation of ethanol. —All distillers grains are wet.	Renewable fuel.
Ethanol	Cellulose and hemicellulose from corn stover, switchgrass, miscanthus, wheat straw, rice straw, sugarcane bagasse, forest waste, yard waste, or planted trees.	—Enzymatic hydrolysis of cellulose. —Fermentation of sugars. —Process heat derived from lignin.	Cellulosic biofuel.
Ethanol	Cellulose and hemicellulose from corn stover, switchgrass, miscanthus, wheat straw, rice straw, sugarcane bagasse, forest waste, yard waste, or planted trees.	—Thermochemical gasification of biomass. —Fischer-Tropsch process.	Cellulosic biofuel.
Ethanol	Sugarcane sugar	—Process heat derived from sugarcane bagasse.	Advanced biofuel.
Biodiesel (mono alkyl ester)	Waste grease, waste oils, tallow, chicken fat, or non-food grade corn oil.	—Transesterification	Biomass-based diesel.
Biodiesel (mono alkyl ester)	Soybean oil and other virgin plant oils.	—Transesterification	Renewable fuel.

TABLE VI.E.4–1—APPLICABLE CATEGORIES FOR EACH FUEL PATHWAY [a]—Continued

Fuel type	Feedstock	Production process requirements	Category
Cellulosic diesel	Cellulose and hemicellulose from corn stover, switchgrass, miscanthus, wheat straw, rice straw, sugarcane bagasse, forest waste, yard waste, or planted trees.	—Thermochemical gasification of biomass.	Cellulosic biofuel or biomass-based diesel.
		—Fischer-Tropsch process.	
		—Catalytic depolymerization.	
Non-ester renewable diesel	Waste grease, waste oils, tallow, chicken fat, or corn oil.	—Hydrotreating.	
		—Dedicated facility that processes only renewable biomass.	Biomass-based diesel.
Non-ester renewable diesel	Waste grease, waste oils, tallow, chicken fat, or non-food grade corn oil.	—Hydrotreating	Advanced biofuel.
		—Coprocessing facility that also processes petroleum feedstocks.	
Non-ester renewable diesel	Soybean oil and other virgin plant oils.	—Hydrotreating	Renewable fuel.
Cellulosic gasoline	Cellulose and hemicellulose from corn stover, switchgrass, miscanthus, wheat straw, rice straw, sugarcane bagasse, forest waste, yard waste, or planted trees.	—Thermochemical gasification of biomass.	Cellulosic biofuel.
		—Fischer-Tropsch process.	
		—Catalytic depolymerization.	

[a] Under our assumed 100-year timeframe and 2% discount rate.

As stated earlier, there may be other potential pathways that could lead to qualifying renewable fuel. While we do not have sufficient information at this time to evaluate the likely lifecycle GHG impact and thus assign those pathways to one of the four renewable fuel categories, we do plan on doing these evaluations for the final rule. Pathways that we intend to subject to lifecycle analysis include butanol from starches or oils and renewable diesel from biomass using pyrolysis or catalytic reforming. We request comment on the inputs necessary to apply lifecycle analysis to these pathways. We also request comment on other pathways that should be analyzed and the data that would be necessary for those analyses.

For pathways that are not included in the lookup table in the final rule, we are also proposing a regulatory mechanism whereby a producer could temporarily assign their renewable fuel to one of the four renewable fuel categories under certain conditions. For further discussion of this issue, see Section III.D.5.

F. Total GHG Emission Reductions

Our analysis of the overall GHG emission impacts of this proposed rulemaking was performed in parallel with the lifecycle analysis performed to develop the individual fuel thresholds described in previous sections. The same system boundaries apply such that this analysis includes the effects of three main areas: (a) emissions related to the production of biofuels, including the growing of feedstock (corn, soybeans, etc.) with associated domestic and international land use change impacts, transport of feedstock to fuel production plants, fuel production, and distribution of finished fuel; (b) emissions related to the extraction, production and distribution of petroleum gasoline and diesel fuel that is replaced by use of biofuels; and (c) difference in tailpipe combustion of the renewable and petroleum based fuels. As discussed in the previous sections we will be updating our lifecycle approach for the final rule and there are some areas that we were not able to quantify at this time, such as secondary impacts in the energy sector. We are working to include this for our final rule analysis.

Consistent with the fuel volume feasibility analysis and criteria pollutant emissions, our analysis of the GHG impacts of increased renewable fuel use was conducted by comparing the impacts of the 2022 36 Bgal of renewable fuel volumes required by EISA to a projected 2022 reference case of approximately 14 Bgal of renewable fuel volumes. Similar to what was done to calculate lifecycle thresholds for individual fuels we considered the change in 2022 of these two volume scenarios of renewable fuels to determine overall GHG impacts of the rule. The reference case for the GHG emission comparisons was taken from the AEO 2007 projected renewable fuel production levels for 2022 prior to enactment of EISA. This scenario provided a point of comparison for assessing the impacts of the RFS2 standard volumes on GHG emissions. We ran these multi-fuel scenarios through our FASOM and FAPRI models and applied the Winrock land use change assumptions to determine to overall GHG impacts. We were only able to analyze 2022 reference and control cases. However, in reality the impacts of corn ethanol and soybean biodiesel will be experienced beginning in 2009, with the impacts of cellulosic ethanol and sugarcane ethanol growing in later years as their volumes increase.

The main difference between this overall impacts analysis and the analysis conducted to develop the threshold values for the individual fuels is that we analyzed the total change in renewable fuels in one scenario as opposed to looking at individual fuel impacts. When analyzing the impact of the total 36 billion gallons of renewable fuel, we also took into account the agricultural sector interactions necessary to produce the full complement of feedstock. We also considered a mix of plant types and configurations for the 2022 renewable fuel production representing the mix of plants we project to be in operation in 2022. This is based on the same analysis used in the plant location and fuel feasibility analysis described in Section V.B.

For this overall impacts analysis we used a different petroleum baseline fuel that is offset from renewable fuel use. The lifecycle threshold values are required by EISA to be based on a 2005 petroleum fuel baseline. For this inventory analysis of the overall impacts of the rule we considered the crude oil and finished product that would be replaced in 2022. Displaced petroleum product analysis was consistent with work performed for the energy security analysis described in Section IX.B. For this analysis we consider that 25% of displaced gasoline will be imported gasoline. For the domestic production we assumed replacement of the 2022 crude mix which is projected to include 7.6% tar sands and 3.8% Venezuelan heavy crude which is higher then the projected mix in 2005 which includes 5% tar sands and 1% Venezuelan heavy crude.

Given these many differences, simply adding up the individual lifecycle results determined in Section VI.C. multiplied by their respective volumes would yield a different assessment of the overall rule impacts. The two analyses are separate in that the overall rule impacts capture interactions between the different fuels that can not be broken out into per fuels impacts, while the threshold values represent impacts of specific fuels but do not account for all the interactions.

For example, when we consider the combined impact of the different fuel volumes when analyzed separately, the overall land use change is 9.0 million acres. However, when we analyze the volume changes all together, the overall land use change is approximately 10% higher.

The primary reason for the difference in acre change between the sum of the individual fuel scenarios and the combined fuel scenarios is that when looking at individual fuels there is some interaction between different crops (e.g., corn replacing soybeans), but with combined volume scenario when all mandates need to be met there is less opportunity for crop replacement (e.g., both corn and soybean acres needed) and therefore more land is required.

Important findings of our analysis include:

- As with the threshold lifecycle calculations, assumptions about timing to consider impacts over and discount rates will have a significant impact on results.
- We estimate the largest overall agricultural sector impact is an increase in land use change impacts, reflecting the shift of crop production internationally to meet the biofuel demand in the U.S. Increased crop production internationally resulted in land use change emissions associated with converting land into crop production.
- Our analysis indicates that overall domestic agriculture emissions would increase. There is a relatively small increase in total domestic crop acres however, there are additional inputs required due to the removal of crop residues. The assumption is that removal will require more inputs to make up for lost residue nutrients. These additional inputs result in GHG emissions from production and from N_2O releases from application. This effect is somewhat offset by reductions due to lower livestock production. These results are dependent on our agricultural sector input and emission assumptions that are being updated for the final rule (e.g., N_2O emission factor work).
- In particular due to this international impact, the potential overall GHG emission reductions of biofuels produced from food crops such as corn ethanol and soy biodiesel are significantly impacted. Large near term emission increases due to land use change require a number of years before the emission reductions due to corn ethanol and soy biodiesel use will offset the near term emission increase as discussed in the threshold calculation section.
- Cellulosic biofuels contribute by far the most to the total emission reductions due to both their superior per gallon emission reductions and the large volume of these fuels anticipated to be used by 2022.

The timing of the impact of land use change and ongoing renewable fuels benefits were discussed in the previous lifecycle fuel threshold section. The issue is slightly different for this analysis since we are considering absolute tons of emissions and not determining a threshold comparison to petroleum fuels. However the results can be presented in a similar manner to our individual fuels analysis in that we can determine net benefits over time with different discount rates and over a different time frame for consideration.

As discussed in previous sections on lifecycle GHG thresholds there is an initial one time release from land conversion and smaller ongoing releases but there are also ongoing benefits of using renewable fuels over time replacing petroleum fuel use. Based on the volume scenario considered, the one time land use change impacts result in 448 million metric tons of CO2–eq. emissions increase. There are, however, based on the biofuel use replacing petroleum fuels, GHG reductions in each year. When modeling the program as if all fuel volume changes occur in 2022, and considering 100 years of emission impacts that are discounted by 2% per year, we get an estimated total discounted NPV reduction in GHG emissions of 6.8 billion tons over 100 years. Totaling the emissions impacts over 30 years but assuming a 0% discount rate over this 30 year period would result in an estimated total NPV reduction in GHG emissions of 4.5 billion tons over 30 years.

This total NPV reduction can be converted into annual average GHG reductions, which can be used for the calculations of the *monetized* GHG benefits as shown in Section IX.C.4. This annualized value is based on converting the lump sum present values described above into their annualized equivalents. For this analysis we convert the NPV results for the 100 year 2% discount rate into an annualized average such that the NPV of the annualized average emissions will equal the NPV of the actual emission stream over 100 years with a 2% discount rate. This results in an annualized average emission reduction of approximately160 million metric tons of CO2–eq. emissions. A comparable value assuming 30 years of GHG emissions changes but not applying a discount rate to those emissions results in an estimated annualized average emission reduction of approximately 150 million metrics tons of CO2–eq. emissions.

G. Effects of GHG Emission Reductions and Changes in Global Temperature and Sea Level

1. Introduction

The reductions in CO_2 and other GHGs associated with the proposal will affect climate change projections. Because GHGs mix well in the atmosphere and have long atmospheric lifetimes, changes in GHG emissions will affect future climate for decades to centuries. One common indicator of climate change is global mean surface temperature and sea level rise. This section estimates the response in global mean surface temperature projections to the estimated net global GHG emissions reductions associated with the proposed rulemaking (See Section VI.F for the estimated net reductions in global emissions over time by GHG).

2. Estimated Projected Reductions in Global Mean Surface Temperatures

EPA estimated changes in projected global mean surface temperatures to 2100 using the MiniCAM (Mini Climate Assessment Model) integrated assessment model [320] coupled with the MAGICC (Model for the Assessment of Greenhouse-gas Induced Climate Change) simple climate model.[321] MiniCAM was used to create the globally and temporally consistent set of climate relevant variables required for running MAGICC. MAGICC was then used to estimate the change in the global mean surface temperature over time. Given the magnitude of the estimated emissions reductions associated with the proposed rule, a simple climate model such as MAGICC is reasonable for estimating the climate response.

EPA applied the estimated annual GHG emissions changes for the proposal to the MiniCAM U.S. Climate Change Science Program (CCSP) Synthesis and Assessment Product baseline emissions.[322] Specifically, the CO_2, N_2O, and CH_4 annual emission changes from 2022–2121 from Section VI.F were applied as net reductions to the MiniCAM CCSP global baseline net emissions for each GHG. Post-2121, we assumed no change in emissions from the baseline. This assumption is more conservative than allowing the emissions reductions to continue.

Table VI.G.2 provides our estimated reductions in projected global mean surface temperatures and sea level associated with the proposed increase in renewable fuels in 2022. To capture some of the uncertainty in the climate system, we estimated the changes in projected temperatures and sea level across the most current Intergovernmental Panel on Climate Change (IPCC) range of climate sensitivities, 1.5 °C to 6.0 °C.[323] To illustrate the time profile of the estimated reductions in projected global mean surface temperatures and sea level, we have also provided Figures VI.G.2–1 and VI.G.2–2.

TABLE VI.G.2–1—ESTIMATED REDUCTIONS IN PROJECTED GLOBAL MEAN SURFACE TEMPERATURE AND GLOBAL MEAN SEA LEVEL FROM BASELINE IN 2030, 2050, 2100, AND 2200 FOR THE PROPOSED STANDARD IN 2022

	Climate sensitivity				
	1.5	2	3	4.5	6
Change in global mean surface temperatures (degrees Celsius)					
2030	0.000	0.000	−0.001	−0.001	−0.001
2050	−0.001	−0.002	−0.002	−0.002	−0.003
2100	−0.003	−0.004	−0.005	−0.006	−0.007
2200	−0.003	−0.004	−0.006	−0.008	−0.009
Change in global mean sea level rise (centimeters)					
2030	−0.002	−0.002	−0.003	−0.003	−0.003
2050	−0.012	−0.014	−0.017	−0.020	−0.022
2100	−0.045	−0.052	−0.063	−0.074	−0.082
2200	−0.077	−0.091	−0.114	−0.143	−0.172

The results in Table VI.G.2–1 and Figures VI.G.2–1 and VI.G.2–2 show small, but detectable, reductions in the global mean surface temperature and sea level rise projections across all climate sensitivities. Overall, the reductions are small relative to the IPCC's ''best estimate'' temperature increases by 2100 of 1.8 °C to 4.0 °C.[324] Although IPCC does not issue ''best estimate'' sea level rise projections, the model-based range across SRES scenarios is 18 to 59 cm by 2099.[325] Both figures illustrate that the overall emissions reductions can decrease projected annual temperature and sea level for all climate sensitivities. This means that the distribution of potential temperatures in any particular year is shifting down. However, the shift is not uniform. The magnitude of the decrease is larger for higher climate

[320] MiniCAM is a long-term, global integrated assessment model of energy, economy, agriculture and land use, that considers the sources of emissions of a suite of greenhouse gases (GHG's), emitted in 14 globally disaggregated global regions (i.e., U.S., Western Europe, China), the fate of emissions to the atmosphere, and the consequences of changing concentrations of greenhouse related gases for climate change. MiniCAM begins with a representation of demographic and economic developments in each region and combines these with assumptions about technology development to describe an internally consistent representation of energy, agriculture, land-use, and economic developments that in turn shape global emissions. Brenkert A, S. Smith, S. Kim, and H. Pitcher, 2003: Model Documentation for the MiniCAM. PNNL–14337, Pacific Northwest National Laboratory, Richland, Washington. For a recent report and detailed description and discussion of MiniCAM, *see* Clarke, L., J. Edmonds, H. Jacoby, H. Pitcher, J. Reilly, R. Richels, 2007. Scenarios of Greenhouse Gas Emissions and Atmospheric Concentrations. Sub-report 2.1A of Synthesis and Assessment Product 2.1 by the U.S. Climate Change Science Program and the Subcommittee on Global Change Research. Department of Energy, Office of Biological & Environmental Research, Washington, DC., USA, 154 pp.

[321] MAGICC consists of a suite of coupled gas-cycle, climate and ice-melt models integrated into a single framework. The framework allows the user to determine changes in GHG concentrations, global-mean surface air temperature and sea-level resulting from anthropogenic emissions of carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), reactive gases (e.g., CO, NO_X, VOCs), the halocarbons (e.g. HCFCs, HFCs, PFCs) and sulfur dioxide (SO2). MAGICC emulates the global-mean temperature responses of more sophisticated coupled Atmosphere/Ocean General Circulation Models (AOGCMs) with high accuracy. Wigley, T.M.L. and Raper, S.C.B. 1992. Implications for Climate and Sea-Level of Revised IPCC Emissions Scenarios Nature 357, 293–300. Raper, S.C.B., Wigley T.M.L. and Warrick R.A. 1996. in Sea-Level Rise and Coastal Subsidence: Causes, Consequences and Strategies J.D. Milliman, B.U. Haq, Eds., Kluwer Academic Publishers, Dordrecht, The Netherlands, pp. 11–45. Wigley, T.M.L. and Raper, S.C.B. 2002. Reasons for larger warming projections in the IPCC Third Assessment Report J. Climate 15, 2945–2952.

[322] Clarke *et al.*, 2007.

[323] In IPCC reports, equilibrium climate sensitivity refers to the equilibrium change in the annual mean global surface temperature following a doubling of the atmospheric equivalent carbon dioxide concentration. The IPCC states that climate sensitivity is ''likely'' to be in the range of 2 °C to 4.5 °C and described 3 °C as a ''best estimate.'' The IPCC goes on to note that climate sensitivity is ''very unlikely'' to be less than 1.5 °C and ''values substantially higher than 4.5 °C cannot be excluded.'' IPCC WGI, 2007, *Climate Change 2007—The Physical Science Basis*, Contribution of Working Group I to the Fourth Assessment Report of the IPCC, *http://www.ipcc.ch/*.

[324] IPCC WGI, 2007. The baseline increases by 2100 from our MiniCAM–MAGICC runs are 2 °C to 5 °C for global mean surface temperature and 35 to 74 centimeters for global mean sea level.

[325] ''Because understanding of some important effects driving sea level rise is too limited, this report does not assess the likelihood, nor provide a best estimate or an upper bound for sea level rise.'' IPCC Synthesis Report, p. 45

sensitivities. Thus, the probability of a higher temperature or sea level in any year is lowered more than the probability of a lower temperature or sea level. For instance, in 2100, the reduction in projected temperature for climate sensitivities of 3 and 6 is approximately 65% and 140% greater than the reduction for a climate sensitivity of 1.5. This difference grows over time, to approximately 80% and 185% by 2200. The same pattern appears in the reductions in the sea level rise projections.[326] Also noteworthy in Figures VI.G.2–1 and VI.G.2–2 is that the size of the decreases grows over time due to the cumulative effect of a lower stock of GHGs in the atmosphere (i.e., concentrations).[327]

The bottom line is that the risk of climate change is being lowered, as the probabilities of any level of temperature increase and sea level rise are reduced and the probabilities of the largest temperature increases and sea level rise are reduced even more. For the Final Rulemaking, we hope to more explicitly estimate the shapes of the distributions and the estimated shifts in the shapes in response to the Rulemakings.

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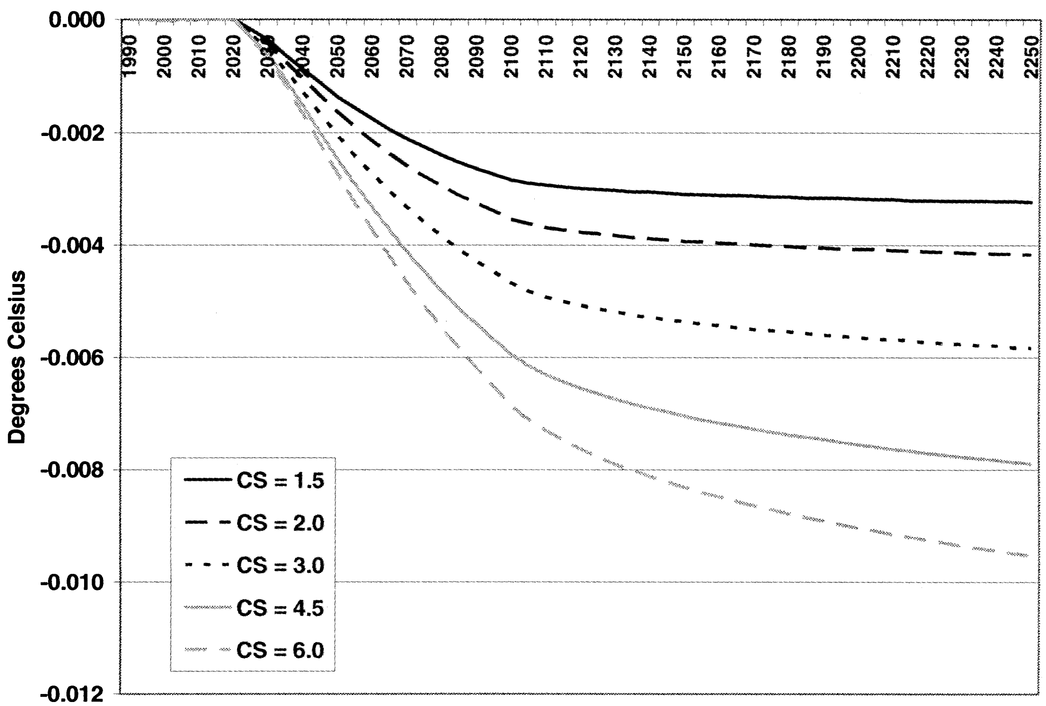
Figure VI.G.2-1

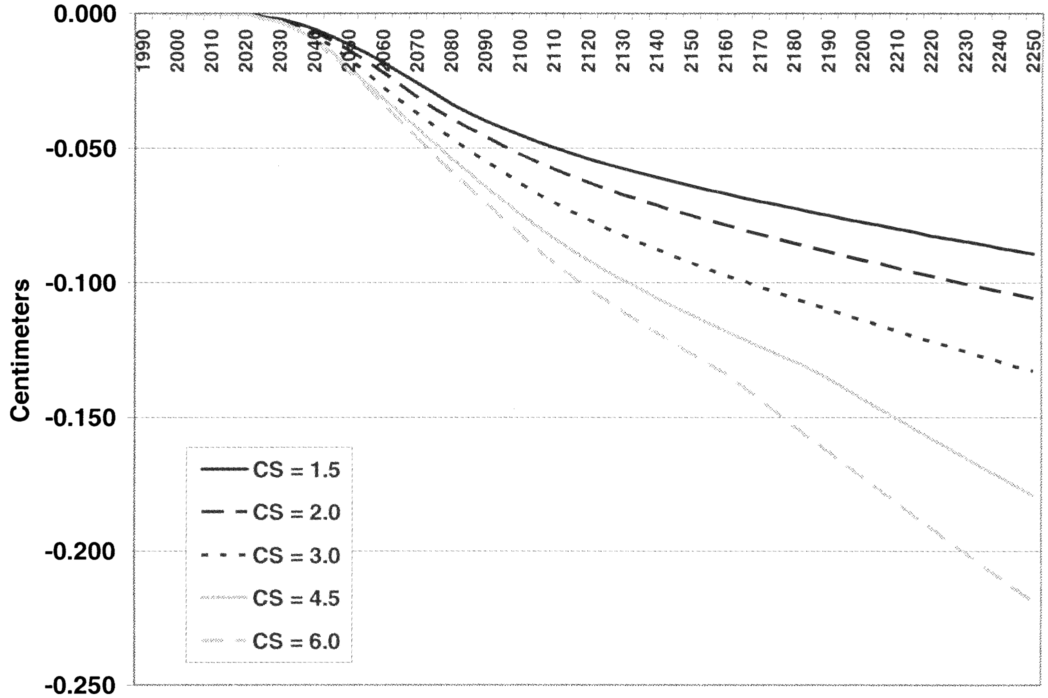
Estimated Projected Reductions in Global Mean Surface Temperatures across Climate Sensitivities (CS) for the Proposed Standard in 2022



[326] In 2100, the reduction in projected sea level rise for climate sensitivities of 3 and 6 is approximately 40% and 80% greater than the reduction for a climate sensitivity of 1.5. This difference grows over time, to approximately 50% and 120% by 2200.

[327] For global average temperature after 2100, the growth in the size of the decrease noticeable slows. This is because the emissions changes associated with the policy were only estimated for 100 years. Note that even with emissions reductions stopping after 100 years, there continues to be a decrease in projected temperatures due to reduced inertia in the climate system from the earlier emissions reductions. However, unlike temperature, after 2100, the size of the decrease in sea level rise increases as the projected reduction in warming has a continued effect on ice melt and ocean thermal expansion.

Figure VI.G.2-2
Estimated Projected Reductions in Global Mean Sea Level across Climate Sensitivities (CS) for the Proposed Standard in 2022



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VII. How Would the Proposal Impact Criteria and Toxic Pollutant Emissions and Their Associated Effects?

A. Overview of Impacts

Today's proposal would influence the emissions of ''criteria'' pollutants (those pollutants for which a National Ambient Air Quality Standard has been established), criteria pollutant precursors,[328] and air toxics, which may affect overall air quality and health. Emissions would be affected by the processes required to produce and distribute large volumes of biofuels proposed in today's action and the direct effects of these fuels on vehicle and equipment emissions. As detailed in Chapter 3 of the Draft Regulatory Impact Analysis (DRIA), we have estimated emissions impacts of production and distribution-related emissions using the life cycle analysis methodology described in Section VI with emission factors for criteria and toxic emissions for each stage of the life cycle, including agriculture, feedstock transportation, and the production and distribution of biofuel; included in this analysis are the impacts of reduced gasoline and diesel refining as these fuels are displaced by biofuels. Emission impacts of tailpipe and evaporative emissions for on and off road sources have been estimated by incorporating ''per vehicle'' fuel effects from recent research into mobile source emission inventory estimation methods.

For today's proposal we are presenting two sets of emission impacts meant to present a range of the possible effects of ethanol blends on light-duty vehicle emissions. This approach is carried forward from analysis supporting the first RFS rule, which presented ''primary'' and ''sensitivity'' fuel effects cases differentiated by E10 effects on cars and trucks. For this analysis we also analyze two fuel effects scenarios, now termed ''less sensitive'' and ''more sensitive,'' referring to the sensitivity of car and truck exhaust emissions to both E10 and E85 blends. As detailed in Section VII.C, the ''less sensitive'' case does not apply any E10 effects to NOx or HC emissions for later model year vehicles, or E85 effects for any pollutant, while the ''more sensitive'' case assumes that later model year vehicles have lower fuel sensitivity than earlier model vehicles. EPA and other parties are in the midst of gathering additional data to help clarify emissions impacts of ethanol on light-duty vehicles, and should be able to reflect the new data for the final rule.

Analysis of criteria and toxic emission impacts was performed for calendar year 2022, since this year reflects the full implementation of today's proposal. Our 2022 projections account for projected growth in vehicle travel and the effects of applicable emission and fuel economy standards, including Tier 2 and Mobile Source Air Toxics (MSAT) rules for cars and light trucks and recently finalized controls on spark-ignited off-road engines. The impacts were analyzed relative to three different reference case ethanol volumes, ranging from 3.64 to 13.2 billion gallons per year, in order to understand the impacts of today's proposal in different contexts. To assess the total impact of the RFS program, emissions were analyzed relative to the RFS1 rule base case of 3.64 billion gallons in 2004. To assess the impact of today's proposal relative to the current mandated volumes, we analyzed impacts relative to RFS1 mandate of 7.5 billion gallons of renewable fuel use by 2012, which was estimated to include 6.7 billion gallons of ethanol.[329] In order to assess the impact of today's proposal relative to the level of ethanol projected to already be in place by 2022, the AEO2007 projection of 13.2 billion gallons of

[328] NO_X and VOC are precursors to the criteria pollutant ozone; we group them with criteria pollutants in this chapter for ease of discussion.

[329] For this analysis these RFS1 base and mandated ethanol levels were assumed constant to 2022.

ethanol in 2022 was analyzed. For this analysis our modeling was based on the differences between the AEO2007 reference case and the control case; to generate impacts for the RFS1 base and mandated volumes we simply scaled the modeled AEO2007-based impacts up according to the larger increases in renewable fuel volumes relative to the other reference cases. For the final rule we plan to directly model the RFS1 mandate reference case as well as the AEO2007 case.

For the proposal we have only estimated the change in national emission totals that would result from today's proposal. These totals may not be a good indication of local or regional air quality and health impacts. These results are aggregated across highly localized sources, such as emissions from ethanol plants and evaporative emissions from cars, and reflect offsets such as decreased emissions from gasoline refineries. The location and composition of emissions from these disparate sources may strongly influence the air quality and health impacts of today's proposed action, and full-scale photochemical air quality modeling is necessary to accurately assess this. These localized impacts will be assessed in the final rule as discussed in Section VII.D.

Our projected emission impacts for the ''less sensitive'' and ''more sensitive'' cases are shown in Table VII.A–1 and VII.A–2 for 2022. Shown relative to each reference case are the expected emission changes for the U.S. in that year, and the percent contribution of this impact relative to the total U.S. inventory. Overall we project the proposed program will result in significant increases in ethanol and acetaldehyde emissions—increasing the total U.S. inventories of these pollutants by 30–40% in 2022 relative to the RFS1 mandate case. We project more modest increases in NO_x, HC, PM, SO_2, formaldehyde, and acrolein relative to the RFS1 mandate case. We project a decrease in ammonia (NH_3) emissions due to reductions in livestock agricultural activity, CO (due to impacts of ethanol on exhaust emissions from vehicles and nonroad equipment), and benzene (due to displacement of gasoline with ethanol in the fuel pool). As shown, the direction of changes for 1,3-butadiene and naphthalene depends on whether it is the ''less sensitive'' or ''more sensitive'' case.

TABLE VII.A–1—RFS2 ''LESS SENSITIVE'' CASE EMISSION IMPACTS IN 2022 RELATIVE TO EACH REFERENCE CASE

Pollutant	RFS1 base		RFS1 mandate		AEO2007	
	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory
NO_x	312,400	2.8	274,982	2.5	195,735	1.7
HC	112,401	1.0	72,362	0.6	−8,193	−0.07
PM_{10}	50,305	1.4	37,147	1.0	9,276	0.3
$PM_{2.5}$	14,321	0.4	11,452	0.3	5,376	0.16
CO	−2,344,646	−4.4	−1,669,872	−3.1	−240,943	−0.4
Benzene	−2,791	−1.7	−2,507	−1.5	−1,894	−1.1
Ethanol	210,680	36.5	169,929	29.4	83,761	14.5
1,3-Butadiene	344	2.9	255	2.1	65	0.5
Acetaldehyde	12,516	33.7	10,369	27.9	5,822	15.7
Formaldehyde	1,647	2.3	1,348	1.9	714	1.0
Naphthalene	5	0.03	3	0.02	−1	−0.01
Acrolein	290	5.0	252	4.4	174	3.0
S_{O2}	28,770	0.3	4,461	0.05	−47,030	−0.5
NH_3	−27,161	−0.6	−27,161	−0.6	−27,161	−0.6

TABLE VII.A–2—RFS2 ''MORE SENSITIVE'' CASE EMISSION IMPACTS IN 2022 RELATIVE TO EACH REFERENCE CASE

Pollutant	RFS1 base		RFS1 Mandate		AEO2007	
	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory
NO_x	402,795	3.6	341,028	3.0	210,217	1.9
HC	100,313	0.9	63,530	0.6	−15,948	−0.14
PM_{10}	46,193	1.3	33,035	0.9	5,164	0.15
$PM_{2.5}$	10,535	0.3	7,666	0.2	1,589	0.05
CO	−3,779,572	−7.0	−3,104,798	−5.8	−1,675,869	−3.1
Benzene	−5,962	−3.5	−5,494	−3.3	−4,489	−2.7
Ethanol	228,563	39.6	187,926	32.5	105,264	18.2
1,3-Butadiene	−212	−1.8	−282	−2.4	−430	−3.6
Acetaldehyde	16,375	44.0	14,278	38.4	9,839	26.5
Formaldehyde	3,373	4.7	3,124	4.3	2,596	3.6
Naphthalene	−175	−1.2	−178	−1.3	−187	−1.3
Acrolein	253	4.4	218	3.8	143	2.5
SO_2	28,770	0.3	4,461	0.05	−47,030	−0.5
NH_3	−27,161	−0.6	−27,161	−0.6	−27,161	−0.6

The breakdown of these results by the fuel production/distribution (''well-to-pump'' emissions) and vehicle and equipment (''pump-to-wheel'') emissions is discussed in the following sections.

B. Fuel Production & Distribution Impacts of the Proposed Program

Fuel production and distribution emission impacts of the proposed program were estimated in conjunction with the development of life cycle GHG emission impacts and the GHG emission inventories discussed in Section VI. These emissions are calculated according to the breakdowns of agriculture, feedstock transport, fuel production, and fuel distribution; the basic calculation is a function of fuel volumes in the analysis year and the emission factors associated with each process or subprocess. Additionally, the emission impact of displaced petroleum is estimated, using the same domestic/import shares discussed in Section VI above.

In general the basis for this life cycle evaluation was the analysis conducted as part of the Renewable Fuel Standard (RFS1) rulemaking, but enhanced significantly. While our approach for the RFS1 was to rely heavily on the ''Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation'' (GREET) model, developed by the Department of Energy's Argonne National Laboratory (ANL), we are now able to take advantage of additional information and models to significantly strengthen and expand our analysis for this proposed rule. In particular, the modeling of the agriculture sector was greatly expanded beyond the RFS1 analysis, employing economic and agriculture models to consider factors such as land-use impact, agricultural burning, fertilizer, pesticide use, livestock, crop allocation, and crop exports.

Other updates and enhancements to the GREET model assumptions include updated feedstock energy requirements and estimates of excess electricity available for sale from new cellulosic ethanol plants, based on modeling by the National Renewable Energy Laboratory (NREL). EPA also updated the fuel and feedstock transport emission factors to account for recent EPA emission standards and modeling, such as the diesel truck standards published in 2001 and the locomotive and commercial marine standards finalized in 2008. Emission factors for new corn ethanol plants continue to use the values developed for the RFS1 rule, which were based on data submitted by states for dry mill plants. There are no new standards planned at this time that would offer any additional control of emissions from corn or cellulosic ethanol plants. In addition, GREET does not include air toxics or ethanol. Thus emission factors for ethanol and the following air toxics were added: benzene, 1,3-butadiene, formaldehyde, acetaldehyde, acrolein and naphthalene.

Results of these calculations relative to each of the reference cases for 2022 are shown in Table VII.B–1 for the criteria pollutants, ammonia, ethanol and individual air toxic pollutants. It should be noted that the impacts relative to the two RFS1 reference cases (3.64 and 6.7 billion gallons) rely on applying ethanol volume proportions to the modeling results of the AEO2007 reference case (13.2 billion gallons). Due to the complex interactions involved in projections in the agricultural modeling, we did not attempt to adjust the agricultural inputs of the AEO reference case for the other two reference cases. So the fertilizer and pesticide quantities, livestock counts, and total agricultural acres were the same for all three reference cases. The agricultural modeling that had been done for the RFS1 rule itself was much simpler and inconsistent with the new modeling, so it would be inappropriate to use those estimates. Thus, we plan to conduct additional agricultural modeling specifically for the RFS1 mandate case prior to finalizing this rule.

The fuel production and distribution impacts of the proposed program on VOC are mainly due to increases in emissions connected with biofuel production, countered by decreases in emissions associated with gasoline production and distribution as ethanol displaces some of the gasoline. Increases in NO_X, $PM_{2.5}$, and SO_X are driven by combustion emissions from the substantial increase in corn and cellulosic ethanol production. Ethanol plants (corn and cellulosic) tend to have greater combustion emissions relative to petroleum refineries on a per-BTU of fuel produced basis. Increases in SO_X emissions are primarily due to corn ethanol production. Ammonia emissions are expected to decrease substantially due to lower livestock counts, which more than offsets increased ammonia from fertilizer use.

Ethanol vapor and most air toxic emissions associated with fuel production and distribution are projected to increase. Relative to the U.S. total reference case emissions with RFS1 mandate ethanol volumes, increases of 10–20% for acetaldehyde and ethanol vapor are especially significant because they are driven directly by the increased ethanol production and distribution. Formaldehyde and acrolein increases are smaller, on the order of 1–5%. Benzene emissions are estimated to decrease by 1% due to decreased gasoline production. There are also very small increases in 1,3-butadiene and decreases in naphthalene relative to the U.S. total emissions.

TABLE VII.B–1—FUEL PRODUCTION AND DISTRIBUTION IMPACTS IN 2022 RELATIVE TO EACH REFERENCE CASE

Pollutant	RFS1 base		RFS1 mandate		AEO2007	
	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory
NO_X	241,041	2.1	222,732	2.0	183,951	1.6
HC	77,295	0.7	46,702	0.4	−17,501	−0.2
PM_{10}	50,482	1.4	37,324	1.1	9,453	0.3
$PM_{2.5}$	14,419	0.4	11,550	0.3	5,473	0.16
CO	186,559	0.3	179,855	0.3	165,656	−0.5
Benzene	−1,670	−1.0	−1,686	−1.0	−1,719	−1.0
Ethanol	115,187	19.9	100,134	17.3	68,379	11.8
1,3-Butadiene	16	0.13	16	0.14	17	0.14
Acetaldehyde	7,460	20.1	6,680	18.0	5,029	13.5
Formaldehyde	877	1.2	800	1.1	638	0.9
Naphthalene	−6	−0.04	−5	−0.04	−4	−0.03
Acrolein	278	4.8	244	4.2	174	3.0

TABLE VII.B–1—FUEL PRODUCTION AND DISTRIBUTION IMPACTS IN 2022 RELATIVE TO EACH REFERENCE CASE—Continued

Pollutant	RFS1 base		RFS1 mandate		AEO2007	
	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory
SO_2	28,770	0.3	4,461	0.05	−47,030	−0.5
NH_3	−27,161	−0.6	−27,161	−0.6	−27,161	−0.6

C. Vehicle and Equipment Emission Impacts of Fuel Program

The effects of the fuel program on vehicle and equipment emissions are a direct function of the effects of these fuels on exhaust and evaporative emissions from vehicles and off-road equipment, and evaporation of fuel from portable containers. To assess these impacts we conducted separate analyses to quantify the emission impacts of additional E10 due to today's proposal on gasoline vehicles, nonroad spark-ignited engines and portable fuel containers; E85 on cars and light trucks; biodiesel on diesel vehicles; and increased refueling events due to lower energy density of biofuels.[330]

For the proposal we have analyzed inventory impacts for two fuel effects scenarios to attempt to bound the potential impacts on ethanol on gasoline-fueled vehicle exhaust emissions:

(1) ''Less Sensitive'': No exhaust VOC or NO_X emission impact on Tier 1 and later vehicles due to E10, and no impact due to E85. This was termed the ''primary'' case in the RFS1 rule.

(2) ''More Sensitive'': VOC and NO_X emission impacts due to E10 based on limited test data from newer technology vehicles that were analyzed as part of the RFS1 rule. This data showed a 7% reduction in exhaust VOC emissions and an 8% increase in per-vehicle NO_X emissions for Tier 1 and later vehicles using E10 relative to E0. The E10 effects are consistent with the ''sensitivity'' case from the RFS1 rule. For RFS2 this case also includes E85 effects reflecting significant increases in acetaldehyde, formaldehyde and ethanol emissions, and reductions in PM and CO.

EPA and other parties are in the midst of gathering additional data on the emission impacts of ethanol fuels on later model vehicles, which we plan to consider in updating our final rule analysis.

We have also estimated the E10 effects on permeation emissions from light-duty vehicles based on testing previously completed by the Coordinating Research Council (CRC). Nonroad spark ignition (SI) emission impacts of E10 were based on EPA's NONROAD model and show trends similar to light duty vehicles. Biodiesel effects for this analysis were based on a new analysis of recent biodiesel testing, detailed in the DRIA, showing a 2% increase in NO_X with a 20% biodiesel blend, a 16% decrease in PM, and a 14% decrease in HC. These results essentially confirm the results of an earlier EPA analysis.

Summarized vehicle and equipment emission impacts in 2022 are shown in Table VII.C–1 and VII.C–2 for the ''less sensitive'' and ''more sensitive'' cases. Table VII.C–3 shows the biodiesel contribution to these impacts, which are comparatively small. While the two fuel effect scenarios only differ with respect to exhaust emissions from cars and trucks, the totals shown below reflect the net impacts from all mobile sources, including car and truck evaporative emissions, off road emissions, and portable fuel containers, using the same emissions impacts for these sources in both cases. Additional breakdowns by mobile source category can be found in Chapter 3 of the DRIA.

As shown in Tables VII.C–1 and VII.C–2, the vehicle and equipment ethanol impacts vary widely between the two fuel effects cases. Under the ''less sensitive'' case, CO and benzene are projected to decrease in 2022 under today's proposal, while NO_X, HC and the other air toxics (except acrolein) are projected to increase due to the impacts of E10. For the ''more sensitive'' case, NO_X impacts are higher and HC impacts lower due to the E10 effects on cars and trucks, and the inclusion of E85 effects leads to larger reductions in CO, benzene and 1,3-butadiene but more significant increases in ethanol, acetaldehyde and formaldehyde. The impacts on acrolein emissions in both cases, and on naphthalene in the ''more sensitive'' case depend on which reference case is considered, with small increases relative to the RFS1 base and mandate cases and a decrease relative to the AEO reference case.

TABLE VII.C–1—2022 VEHICLE AND EQUIPMENT ''LESS SENSITIVE'' CASE EMISSION IMPACTS BY FUEL TYPE RELATIVE TO EACH REFERENCE CASE

Pollutant	RFS1 base		RFS1 mandate		AEO2007	
	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory
NO_X	71,359	0.6	52,250	0.5	11,784	0.11
HC	35,106	0.3	25,659	0.2	9,308	0.08
PM_{10}	−177	0.00	−177	0.00	−177	0.00
$PM_{2.5}$	−98	0.00	−98	0.00	−98	0.00
CO	−2,531,205	−4.7	−1,849,728	−3.4	−406,599	−0.8
Benzene	−1,122	−0.7	−821	−0.5	−174	−0.1
Ethanol	95,493	16.5	69,795	12.1	15,383	2.7
1,3-Butadiene	328	2.7	238	2.0	48	0.4
Acetaldehyde	5,057	13.6	3,689	9.9	793	2.1

[330] The impact of renewable diesel was not estimated for the proposal; we expect little overall impact on criteria and toxic emissions due to the relatively small volume change, and because emission effects relative to conventional diesel are presumed to be negligible.

TABLE VII.C–1—2022 VEHICLE AND EQUIPMENT "LESS SENSITIVE" CASE EMISSION IMPACTS BY FUEL TYPE RELATIVE TO EACH REFERENCE CASE—Continued

Pollutant	RFS1 base		RFS1 mandate		AEO2007	
	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory
Formaldehyde	771	1.1	548	0.8	76	0.11
Naphthalene	10	0.07	8	0.05	3	0.02
Acrolein	12	0.2	8	0.14	−0.4	−0.01
SO_2	0	0.0	0	0.0	0	0.0
NH_3	0	0.0	0	0.0	0	0.0

TABLE VII.C–2—2022 VEHICLE AND EQUIPMENT "MORE SENSITIVE" CASE EMISSION IMPACTS BY FUEL TYPE RELATIVE TO EACH REFERENCE CASE

Pollutant	RFS1 base		RFS1 mandate		AEO2007	
	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory
NO_X	161,754	1.4	118,295	1.1	26,266	0.2
HC	23,018	0.2	16,828	0.15	1,553	0.01
PM_{10}	−4,289	−0.12	−4,289	−0.12	−4,289	−0.12
$PM_{2.5}$	−3,884	−0.12	−3,884	−0.12	−3,884	−0.12
CO	−3,966,131	−7.4	−3,284,654	−6.1	−1,841,524	−3.4
Benzene	−4,293	−2.6	−3,808	−2.3	−2,770	−1.6
Ethanol	113,376	19.6	87,792	15.2	36,886	6.4
1,3-Butadiene	−228	−1.9	−298	−2.5	−446	−3.7
Acetaldehyde	8,915	24.0	7,598	20.4	4,809	12.9
Formaldehyde	2,497	3.5	2,324	3.2	1,958	2.7
Naphthalene	−170	−1.2	−172	−1.2	−182	−1.3
Acrolein	−25	−0.4	−27	−0.5	−31	−0.5
SO_2	0	0.0	0	0.0	0	0.0
NH_3	0	0.0	0	0.0	0	0.0

TABLE VII.C–3—2022 VEHICLE AND EQUIPMENT BIODIESEL EMISSION IMPACTS RELATIVE TO ALL REFERENCE CASES

[these impacts are included in Tables VII.C–1 and VII.C–2]

Pollutant	Biodiesel impacts
	Annual short tons
NO_X	418
HC	−753
PM_{10}	−177
$PM_{2.5}$	−98
CO	−1,275
Benzene	−9.4
Ethanol	0.0
1,3-Butadiene	−5.1
Acetaldehyde	−21
Formaldehyde	−57
Naphthalene	−0.12
Acrolein	−2.7
SO_2	0.0
NH_3	0.0

D. Air Quality Impacts

Although the purpose of this proposal is to implement the renewable fuel requirements established by the Energy Independence and Security Act (EISA) of 2007, this proposed rule would also impact emissions of criteria and air toxic pollutants. We first present current levels of $PM_{2.5}$, ozone and air toxics and then discuss the national-scale air quality modeling analysis that will be performed for the final rule.

1. Current Levels of $PM_{2.5}$, Ozone and Air Toxics

This proposal may have impacts on levels of $PM_{2.5}$, ozone and air toxics.[331] Nationally, levels of $PM_{2.5}$, ozone and air toxics are declining.[332] [333] However, as of December 16, 2008, approximately 88 million people live in the 39 areas that are designated as nonattainment for the 1997 $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS) and approximately 132 million people live in the 57 areas that are designated as nonattainment for the 1997 8-hour ozone NAAQS. The 1997 $PM_{2.5}$ NAAQS was recently revised and the 2006 24-hour $PM_{2.5}$ NAAQS became effective on December 18, 2006. Area designations for the 2006 24-hour $PM_{2.5}$ NAAQS are expected to be promulgated in 2009 and become effective 90 days after publication in the **Federal Register**. In addition, the majority of Americans continue to be exposed to ambient concentrations of air toxics at levels which have the potential to cause adverse health effects.[334] The levels of air toxics to which people are exposed vary depending on where people live and work and the kinds of activities in which they engage, as discussed in

[331] The proposed standards may also impact levels of ambient CO, a criteria pollutant (see Table VII.A–1 above for co-pollutant emission impacts). For this analysis, however, we focus on the proposal's impacts on ambient $PM_{2.5}$ and ozone formation, since CO is a relatively minor problem in comparison to some of the other criteria pollutants. For example, as of August 15, 2008 there are approximately 675,000 people living in 3 areas (which include 4 counties) that are designated as nonattainment for CO.

[332] U.S. EPA (2003) National Air Quality and Trends Report, 2003 Special Studies Edition. Office of Air Quality Planning and Standards, Research Triangle Park, NC. Publication No. EPA 454/R–03–005. *http://www.epa.gov/air/airtrends/aqtrnd03/ http://www.epa.gov/air/airtrends/aqtrnd03/*.

[333] U.S. EPA (2007) Final Regulatory Impact Analysis: Control of Hazardous Air Pollutants from Mobile Sources, Office of Transportation and Air Quality, Ann Arbor, MI, Publication No. EPA420–R–07–002. *http://www.epa.gov/otaq/toxics.htm*

[334] U.S. Environmental Protection Agency (2007). Control of Hazardous Air Pollutants from Mobile Sources; Final Rule. 72 FR 8434, February 26, 2007.

detail in U.S. EPA's recent Mobile Source Air Toxics Rule.[335]

EPA has already adopted many emission control programs that are expected to reduce ambient $PM_{2.5}$, ozone and air toxics levels. These control programs include the Small SI and Marine SI Engine Rule (73 FR 59034, October 8, 2008), Locomotive and Commercial Marine Rule (73 FR 25098, May 6, 2008), Mobile Source Air Toxics Rule (72 FR 8428, February 26, 2007), Clean Air Interstate Rule (70 FR 25162, May 12, 2005), Clean Air Nonroad Diesel Rule (69 FR 38957, June 29, 2004), Heavy Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements (66 FR 5002, Jan. 18, 2001) and the Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements (65 FR 6698, Feb. 10, 2000). As a result of these programs, the ambient concentration of air toxics, $PM_{2.5}$ and ozone in the future is expected to decrease.

2. Impacts of Proposed Standards on Future Ambient Concentrations of $PM_{2.5}$, Ozone and Air Toxics

The atmospheric chemistry related to ambient concentrations of $PM_{2.5}$, ozone and air toxics is very complex, making predictions based solely on emissions changes extremely difficult. For the final rule, a national-scale air quality modeling analysis will be performed to analyze the impacts of the proposed standards on ambient concentrations of $PM_{2.5}$, ozone, and selected air toxics (i.e., benzene, formaldehyde, acetaldehyde, ethanol, acrolein and 1,3-butadiene). The length of time needed to prepare necessary inventory and model updates has precluded us from performing air quality modeling for this proposal.

The air quality modeling we plan to perform (described more specifically below), will allow us to account for changes in the spatial distribution of PM and PM precursors, and changes in VOC speciation which could impact secondary PM formation. For example, reductions in aromatics in gasoline may reduce ambient PM concentrations by reducing secondary PM formation. Section 3.3 of the Draft Regulatory Impact Analysis (DRIA) for this proposal contains more information on aromatics and secondary aerosol formation.

In addition, air quality modeling will account for changes in fuel type and spatial distribution of fuels that would change emissions of ozone precursor species and thus could affect ozone concentrations. Section 3.3 of the DRIA for this proposed rule provides more detail on the atmospheric chemistry and potential changes in ozone formation due to increased usage of ethanol fuels.

Section VII.A above presents projections of the changes in air toxics emissions due to the proposed standards. The substantial increase in emissions of ethanol and acetaldehyde suggests a likely increase in ambient levels of acetaldehyde from both direct emissions and secondary formation as ethanol breaks down in the atmosphere. Formaldehyde and acrolein emissions would also increase somewhat, while emissions of benzene and 1,3-butadiene would decrease as a result of the proposed standards. Full-scale photochemical modeling is necessary to provide the needed spatial and temporal detail to more completely and accurately estimate the changes in ambient levels of these pollutants.

For the final rule, EPA intends to use a 2005-based Community Multi-scale Air Quality (CMAQ) modeling platform as the tool for the air quality modeling. The CMAQ modeling system is a comprehensive three-dimensional grid-based Eulerian air quality model designed to estimate the formation and fate of oxidant precursors, primary and secondary PM concentrations and deposition, and air toxics, over regional and urban spatial scales (e.g., over the contiguous U.S.).[336 337 338] The CMAQ model is a well-known and well-established tool and is commonly used by EPA for regulatory analyses, for instance the recent ozone NAAQS proposal, and by States in developing attainment demonstrations for their State Implementation Plans.[339] The CMAQ model (version 4.6) was peer-reviewed in February of 2007 for EPA as reported in ''Third Peer Review of CMAQ Model,'' and the peer review report for version 4.7 (described below) is currently being finalized.[340]

CMAQ includes many science modules that simulate the emission, production, decay, deposition and transport of organic and inorganic gas-phase and particle-phase pollutants in the atmosphere. We intend to use the most recent CMAQ version (version 4.7) which was officially released by EPA's Office of Research and Development (ORD) in December 2008, and reflects updates to earlier versions in a number of areas to improve the underlying science. These include (1) enhanced secondary organic aerosol (SOA) mechanism to include chemistry of isoprene, sesquiterpene, and aged in-cloud biogenic SOA in addition to terpene; (2) improved vertical convective mixing; (3) improved heterogeneous reaction involving nitrate formation; and (4) an updated gas-phase chemistry mechanism, Carbon Bond 05 (CB05), with extensions to model explicit concentrations of air toxic species as well as chlorine and mercury. This mechanism, CB05-toxics, also computes concentrations of species that are involved in aqueous chemistry and that are precursors to aerosols. Section 3.3.3 of the DRIA for this proposal discusses SOA formation and details about the improvements made to the SOA mechanism within this recent release of CMAQ.

E. Health Effects of Criteria and Air Toxic Pollutants

1. Particulate Matter

a. Background

Particulate matter (PM) represents a broad class of chemically and physically diverse substances. It can be principally characterized as discrete particles that exist in the condensed (liquid or solid) phase spanning several orders of magnitude in size. PM is further described by breaking it down into size fractions. PM_{10} refers to particles generally less than or equal to 10 micrometers (μm) in aerodynamic diameter. $PM_{2.5}$ refers to fine particles, generally less than or equal to 2.5 μm in aerodynamic diameter. Inhalable (or ''thoracic'') coarse particles refer to those particles generally greater than 2.5 μm but less than or equal to 10 μm in aerodynamic diameter. Ultrafine PM refers to particles less than 100 nanometers (0.1 μm) in aerodynamic diameter. Larger particles tend to be removed by the respiratory clearance mechanisms (e.g., coughing), whereas

[335] U.S. Environmental Protection Agency (2007). Control of Hazardous Air Pollutants from Mobile Sources; Final Rule. 72 FR 8434, February 26, 2007.

[336] U.S. Environmental Protection Agency, Byun, D.W., and Ching, J.K.S., Eds, 1999. Science algorithms of EPA Models-3 Community Multiscale Air Quality (CMAQ modeling system, EPA/600/R–99/030, Office of Research and Development).

[337] Byun, D.W., and Schere, K.L., 2006. Review of the Governing Equations, Computational Algorithms, and Other Components of the Models-3 Community Multiscale Air Quality (CMAQ) Modeling System, J. Applied Mechanics Reviews, 59 (2), 51–77.

[338] Dennis, R.L., Byun, D.W., Novak, J.H., Galluppi, K.J., Coats, C.J., and Vouk, M.A., 1996. The next generation of integrated air quality modeling: EPA's Models-3, Atmospheric Environment, 30, 1925–1938.

[339] U.S. EPA (2007). Regulatory Impact Analysis of the Proposed Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone. EPA document number 442/R–07–008, July 2007.

[340] Aiyyer, A., Cohan, D., Russell, A., Stockwell, W., Tanrikulu, S., Vizuete, W., Wilczak, J., 2007. Final Report: Third Peer Review of the CMAQ Model. p. 23.

smaller particles are deposited deeper in the lungs.

Fine particles are produced primarily by combustion processes and by transformations of gaseous emissions (e.g., SO_X, NO_X and VOC) in the atmosphere. The chemical and physical properties of $PM_{2.5}$ may vary greatly with time, region, meteorology and source category. Thus, $PM_{2.5}$ may include a complex mixture of different pollutants including sulfates, nitrates, organic compounds, elemental carbon and metal compounds. These particles can remain in the atmosphere for days to weeks and travel hundreds to thousands of kilometers.

b. Health Effects of PM

Scientific studies show ambient PM is associated with a series of adverse health effects. These health effects are discussed in detail in the 2004 EPA Particulate Matter Air Quality Criteria Document (PM AQCD), and the 2005 PM Staff Paper.[341] [342] Further discussion of health effects associated with PM can also be found in the DRIA for this rule.

Health effects associated with short-term exposures (hours to days) to ambient PM include premature mortality, increased hospital admissions, heart and lung diseases, increased cough, adverse lower-respiratory symptoms, decrements in lung function and changes in heart rate rhythm and other cardiac effects. Studies examining populations exposed to different levels of air pollution over a number of years, including the Harvard Six Cities Study and the American Cancer Society Study, show associations between long-term exposure to ambient $PM_{2.5}$ and both total and cardiovascular and respiratory mortality.[343] In addition, a reanalysis of the American Cancer Society Study shows an association between fine particle and sulfate concentrations and lung cancer mortality.[344]

[341] U.S. EPA (2004) Air Quality Criteria for Particulate Matter (Oct. 2004), Volume I Document No. EPA600/P–99/002aF and Volume II Document No. EPA600/P–99/002bF. This document is available in Docket EPA–HQ–OAR–2005–0161.

[342] U.S. EPA (2005) Review of the National Ambient Air Quality Standard for Particulate Matter: Policy Assessment of Scientific and Technical Information, OAQPS Staff Paper. EPA–452/R–05–005. This document is available in Docket EPA–HQ–OAR–2005–0161.

[343] Dockery, D.W.; Pope, C.A. III: Xu, X.; et al. 1993. An association between air pollution and mortality in six U.S. cities. N Engl J Med 329:1753–1759.

[344] Pope, C.A., III; Burnett, R.T.; Thun, M.J.; Calle, E.E.; Krewski, D.; Ito, K.; Thurston, G.D. (2002) Lung cancer, cardiopulmonary mortality, and long-term exposure to fine particulate air pollution. J. Am. Med. Assoc. 287:1132–1141.

2. Ozone

a. Background

Ground-level ozone pollution is typically formed by the reaction of volatile organic compounds (VOC) and nitrogen oxides (NO_X) in the lower atmosphere in the presence of heat and sunlight. These pollutants, often referred to as ozone precursors, are emitted by many types of pollution sources, such as highway and nonroad motor vehicles and engines, power plants, chemical plants, refineries, makers of consumer and commercial products, industrial facilities, and smaller area sources.

The science of ozone formation, transport, and accumulation is complex.[345] Ground-level ozone is produced and destroyed in a cyclical set of chemical reactions, many of which are sensitive to temperature and sunlight. When ambient temperatures and sunlight levels remain high for several days and the air is relatively stagnant, ozone and its precursors can build up and result in more ozone than typically occurs on a single high-temperature day. Ozone can be transported hundreds of miles downwind from precursor emissions, resulting in elevated ozone levels even in areas with low local VOC or NO_X emissions.

b. Health Effects of Ozone

The health and welfare effects of ozone are well documented and are assessed in EPA's 2006 Ozone Air Quality Criteria Document (ozone AQCD) and 2007 Staff Paper.[346] [347] Ozone can irritate the respiratory system, causing coughing, throat irritation, and/or uncomfortable sensation in the chest. Ozone can reduce lung function and make it more difficult to breathe deeply; breathing may also become more rapid and shallow than normal, thereby limiting a person's activity. Ozone can also aggravate asthma, leading to more asthma attacks that require medical attention and/or the use of additional medication. In addition, there is suggestive evidence of a contribution of ozone to cardiovascular-related morbidity and highly suggestive evidence that short-term ozone exposure directly or indirectly contributes to non-accidental and cardiopulmonary-related mortality, but additional research is needed to clarify the underlying mechanisms causing these effects. In a recent report on the estimation of ozone-related premature mortality published by the National Research Council (NRC), a panel of experts and reviewers concluded that short-term exposure to ambient ozone is likely to contribute to premature deaths and that ozone-related mortality should be included in estimates of the health benefits of reducing ozone exposure.[348] Animal toxicological evidence indicates that with repeated exposure, ozone can inflame and damage the lining of the lungs, which may lead to permanent changes in lung tissue and irreversible reductions in lung function. People who are more susceptible to effects associated with exposure to ozone can include children, the elderly, and individuals with respiratory disease such as asthma. Those with greater exposures to ozone, for instance due to time spent outdoors (e.g., children and outdoor workers), are also of particular concern.

The 2006 ozone AQCD also examined relevant new scientific information that has emerged in the past decade, including the impact of ozone exposure on such health effects as changes in lung structure and biochemistry, inflammation of the lungs, exacerbation and causation of asthma, respiratory illness-related school absence, hospital admissions and premature mortality. Animal toxicological studies have suggested potential interactions between ozone and PM, with increased responses observed to mixtures of the two pollutants compared to either ozone or PM alone. The respiratory morbidity observed in animal studies along with the evidence from epidemiologic studies supports a causal relationship between acute ambient ozone exposures and increased respiratory-related emergency room visits and hospitalizations in the warm season. In addition, there is

[345] U.S. EPA Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final). U.S. Environmental Protection Agency, Washington, D.C., EPA 600/R–05/004aF–cF, 2006. This document is available in Docket EPA–HQ–OAR–2005–0161. This document may be accessed electronically at: *http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_cr_cd.html*.

[346] U.S. EPA Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final). U.S. Environmental Protection Agency, Washington, DC, EPA 600/R–05/004aF–cF, 2006. This document is available in Docket EPA–HQ–OAR–2005–0161. This document may be accessed electronically at: *http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_cr_cd.html*.

[347] U.S. EPA (2007) Review of the National Ambient Air Quality Standards for Ozone, Policy Assessment of Scientific and Technical Information. OAQPS Staff Paper.EPA–452/R–07–003. This document is available in Docket EPA–HQ–OAR–2005–0161. This document is available electronically at: *http:www.epa.gov/ttn/naaqs/standards/ozone/s_o3_cr_sp.html.*.

[348] National Research Council (NRC), 2008. Estimating Mortality Risk Reduction and Economic Benefits from Controlling Ozone Air Pollution. The National Academies Press: Washington, DC.

suggestive evidence of a contribution of ozone to cardiovascular-related morbidity and non-accidental and cardiopulmonary mortality.

3. Carbon Monoxide

Carbon monoxide (CO) forms as a result of incomplete fuel combustion. CO enters the bloodstream through the lungs, forming carboxyhemoglobin and reducing the delivery of oxygen to the body's organs and tissues. The health threat from CO is most serious for those who suffer from cardiovascular disease, particularly those with angina or peripheral vascular disease. Healthy individuals also are affected, but only at higher CO levels. Exposure to elevated CO levels is associated with impairment of visual perception, work capacity, manual dexterity, learning ability and performance of complex tasks. Carbon monoxide also contributes to ozone nonattainment since carbon monoxide reacts photochemically in the atmosphere to form ozone.[349] Additional information on CO related health effects can be found in the Carbon Monoxide Air Quality Criteria Document (CO AQCD).[350]

4. Air Toxics

The population experiences an elevated risk of cancer and noncancer health effects from exposure to the class of pollutants known collectively as "air toxics."[351] Fuel combustion contributes to ambient levels of air toxics that can include, but are not limited to, acetaldehyde, acrolein, benzene, 1,3-butadiene, formaldehyde, ethanol, naphthalene and peroxyacetyl nitrate (PAN). Acrolein, benzene, 1,3-butadiene, formaldehyde and naphthalene have significant contributions from mobile sources and were identified as national or regional risk drivers in the 1999 National-scale Air Toxics Assessment (NATA).[352] PAN, which is formed from precursor compounds by atmospheric processes, is not assessed in NATA. Emissions and ambient concentrations of compounds are discussed in the DRIA chapter on emission inventories and air quality (Chapter 3).

a. Acetaldehyde

Acetaldehyde is classified in EPA's IRIS database as a probable human carcinogen, based on nasal tumors in rats, and is considered toxic by the inhalation, oral, and intravenous routes.[353] Acetaldehyde is reasonably anticipated to be a human carcinogen by the U.S. DHHS in the 11th Report on Carcinogens and is classified as possibly carcinogenic to humans (Group 2B) by the IARC.[354] [355] EPA is currently conducting a reassessment of cancer risk from inhalation exposure to acetaldehyde.

The primary noncancer effects of exposure to acetaldehyde vapors include irritation of the eyes, skin, and respiratory tract.[356] In short-term (4 week) rat studies, degeneration of olfactory epithelium was observed at various concentration levels of acetaldehyde exposure.[357] [358] Data from these studies were used by EPA to develop an inhalation reference concentration. Some asthmatics have been shown to be a sensitive subpopulation to decrements in functional expiratory volume (FEV1 test) and bronchoconstriction upon acetaldehyde inhalation.[359] The agency is currently conducting a reassessment of the health hazards from inhalation exposure to acetaldehyde.

b. Acrolein

EPA determined in 2003 that the human carcinogenic potential of acrolein could not be determined because the available data were inadequate. No information was available on the carcinogenic effects of acrolein in humans and the animal data provided inadequate evidence of carcinogenicity.[360] The IARC determined in 1995 that acrolein was not classifiable as to its carcinogenicity in humans.[361]

Acrolein is extremely acrid and irritating to humans when inhaled, with acute exposure resulting in upper respiratory tract irritation, mucus hypersecretion and congestion. Levels considerably lower than 1 ppm (2.3 mg/m^3) elicit subjective complaints of eye and nasal irritation and a decrease in the respiratory rate.[362] [363] Lesions to the lungs and upper respiratory tract of rats, rabbits, and hamsters have been observed after subchronic exposure to acrolein. Based on animal data, individuals with compromised respiratory function (e.g., emphysema, asthma) are expected to be at increased risk of developing adverse responses to strong respiratory irritants such as acrolein. This was demonstrated in mice with allergic airway disease by comparison to non-diseased mice in a study of the acute respiratory irritant effects of acrolein.[364]

The intense irritancy of this carbonyl has been demonstrated during controlled tests in human subjects, who suffer intolerable eye and nasal mucosal sensory reactions within minutes of exposure.[365]

c. Benzene

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure, and concludes that exposure is associated with additional health effects, including

[349] U.S. EPA (2000). Air Quality Criteria for Carbon Monoxide, EPA/600/P–99/001F. This document is available in Docket EPA–HQ–OAR–2005–0161.

[350] U.S. EPA (2000). Air Quality Criteria for Carbon Monoxide, EPA/600/P–99/001F. This document is available in Docket EPA–HQ–OAR–2005–0161.

[351] U. S. EPA. 1999 National-Scale Air Toxics Assessment. *http://www.epa.gov/ttn/atw/nata1999/risksum.html*

[352] U.S. EPA. 2006. National-Scale Air Toxics Assessment for 1999. *http://www.epa.gov/ttn/atw/nata1999*

[353] U.S. EPA. 1991. Integrated Risk Information System File of Acetaldehyde. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at.

[354] U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: *ntp.niehs.nih.gov/index.cfm?objectid=32BA9724-F1F6-975E-7FCE50709CB4C932.*

[355] International Agency for Research on Cancer (IARC). 1999. Re-evaluation of some organic chemicals, hydrazine, and hydrogen peroxide. IARC Monographs on the Evaluation of Carcinogenic Risk of Chemical to Humans, Vol 71. Lyon, France.

[356] U.S. EPA. 1991. Integrated Risk Information System File of Acetaldehyde. This material is available electronically at *http://www.epa.gov/iris/subst/0290.htm.*

[357] Appleman, L. M., R. A. Woutersen, V. J. Feron, R. N. Hooftman, and W. R. F. Notten. 1986. Effects of the variable versus fixed exposure levels on the toxicity of acetaldehyde in rats. *J. Appl. Toxicol.* 6: 331–336.

[358] Appleman, L.M., R.A. Woutersen, and V.J. Feron. 1982. Inhalation toxicity of acetaldehyde in rats. I. Acute and subacute studies. *Toxicology.* 23: 293–297.

[359] Myou, S.; Fujimura, M.; Nishi, K.; Ohka, T.; and Matsuda, T. 1993. Aerosolized acetaldehyde induces histamine-mediated bronchoconstriction in asthmatics. *Am. Rev. Respir. Dis.* 148 (4 Pt 1): 940–3.

[360] U.S. EPA. 2003. Integrated Risk Information System File of Acrolein. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available at *http://www.epa.gov/iris/subst/0364.htm.*

[361] International Agency for Research on Cancer (IARC). 1995. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 63, Dry cleaning, some chlorinated solvents and other industrial chemicals, World Health Organization, Lyon, France.

[362] Weber-Tschopp, A.; Fischer, T.; Gierer, R.; *et al.* (1977) Experimentelle reizwirkungen von Acrolein auf den Menschen. Int Arch Occup Environ Hlth 40(2):117–130. In German.

[363] Sim, V.M.; Pattle, R.E. (1957) Effect of possible smog irritants on human subjects. J Am Med Assoc 165(15):1908–1913.

[364] Morris J.B., Symanowicz P.T., Olsen J.E., *et al.* 2003. Immediate sensory nerve-mediated respiratory responses to irritants in healthy and allergic airway-diseased mice. J Appl Physiol 94(4):1563–1571.

[365] Sim V.M., Pattle R.E. Effect of possible smog irritants on human subjects. JAMA 165:1980–2010, 1957.

genetic changes in both humans and animals and increased proliferation of bone marrow cells in mice.[366 367 368] EPA states in its IRIS database that data indicate a causal relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The International Agency for Research on Carcinogens (IARC) has determined that benzene is a human carcinogen and the U.S. Department of Health and Human Services (DHHS) has characterized benzene as a known human carcinogen.[369 370]

A number of adverse noncancer health effects including blood disorders, such as preleukemia and aplastic anemia, have also been associated with long-term exposure to benzene.[371 372] The most sensitive noncancer effect observed in humans, based on current data, is the depression of the absolute lymphocyte count in blood.[373 374] In addition, recent work, including studies sponsored by the Health Effects Institute (HEI), provides evidence that biochemical responses are occurring at lower levels of benzene exposure than previously known.[375 376 377 378] EPA's IRIS program has not yet evaluated these new data.

d. 1,3-Butadiene

EPA has characterized 1,3-butadiene as carcinogenic to humans by inhalation.[379 380] The IARC has determined that 1,3-butadiene is a human carcinogen and the U.S. DHHS has characterized 1,3-butadiene as a known human carcinogen.[381 382] There are numerous studies consistently demonstrating that 1,3-butadiene is metabolized into genotoxic metabolites by experimental animals and humans. The specific mechanisms of 1,3-butadiene-induced carcinogenesis are unknown; however, the scientific evidence strongly suggests that the carcinogenic effects are mediated by genotoxic metabolites. Animal data suggest that females may be more sensitive than males for cancer effects associated with 1,3-butadiene exposure; there are insufficient data in humans from which to draw conclusions about sensitive subpopulations. 1,3-butadiene also causes a variety of reproductive and developmental effects in mice; no human data on these effects are available. The most sensitive effect was ovarian atrophy observed in a lifetime bioassay of female mice.[383]

e. Ethanol

EPA is conducting an assessment of the cancer and noncancer effects of exposure to ethanol, a compound which is not currently listed in EPA's IRIS. A description of these effects to the extent that information is available will be presented, as required by Section 1505 of EPAct, in a report to Congress on public health, air quality and water resource impacts of fuel additives. We expect to release that report in 2009.

Extensive data are available regarding adverse health effects associated with the ingestion of ethanol while data on inhalation exposure effects are sparse. As part of the IRIS assessment, pharmacokinetic models are being evaluated as a means of extrapolating across species (animal to human) and across exposure routes (oral to inhalation) to better characterize the health hazards and dose-response relationships for low levels of ethanol exposure in the environment.

The IARC has classified ''alcoholic beverages'' as carcinogenic to humans based on sufficient evidence that malignant tumors of the mouth, pharynx, larynx, esophagus, and liver are causally related to the consumption of alcoholic beverages.[384] The U.S. DHHS in the 11th Report on Carcinogens also identified ''alcoholic beverages'' as a known human carcinogen (they have not evaluated the cancer risks specifically from exposure to ethanol), with evidence for cancer of the mouth, pharynx, larynx, esophagus, liver and breast.[385] There are no studies reporting carcinogenic effects from inhalation of ethanol. EPA is currently evaluating the available human and animal cancer data to identify which cancer type(s) are the most relevant to an assessment of risk to humans from a low-level oral and inhalation exposure to ethanol.

Noncancer health effects data are available from animal studies as well as epidemiologic studies. The epidemiologic data are obtained from studies of alcoholic beverage

[366] U.S. EPA. 2000. Integrated Risk Information System File for Benzene. This material is available electronically at *http://www.epa.gov/iris/subst/0276.htm*.

[367] International Agency for Research on Cancer (IARC). 1982. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Some industrial chemicals and dyestuffs, World Health Organization, Lyon, France, p. 345–389.

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[369] International Agency for Research on Cancer (IARC). 1987. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Supplement 7, Some industrial chemicals and dyestuffs, World Health Organization, Lyon, France.

[370] U.S. Department of Health and Human Services National Toxicology Program, 11th Report on Carcinogens, available at: *http://ntp.niehs.nih.gov/go/16183*.

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[374] U.S. EPA (2002) Toxicological Review of Benzene (Noncancer Effects). Environmental Protection Agency, Integrated Risk Information System (IRIS), Research and Development, National Center for Environmental Assessment, Washington DC. This material is available electronically at *http://www.epa.gov/iris/subst/0276.htm*.

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[376] Qu, Q., R. Shore, G. Li, X. Jin, L.C. Chen, B. Cohen, *et al.* (2002) Hematological changes among Chinese workers with a broad range of benzene exposures. Am. J. Industr. Med. 42:275–285.

[377] Lan, Qing, Zhang, L., Li, G., Vermeulen, R., *et al.* (2004) Hematotoxicity in Workers Exposed to Low Levels of Benzene. Science 306:1774–1776.

[378] Turtletaub, K.W. and Mani, C. (2003) Benzene metabolism in rodents at doses relevant to human exposure from Urban Air. Research Reports Health Effect Inst. Report No. 113.

[379] U.S. EPA (2002) Health Assessment of 1,3–Butadiene. Office of Research and Development, National Center for Environmental Assessment, Washington Office, Washington, DC. Report No. EPA600–P–98–001F. This document is available electronically at *http://www.epa.gov/iris/supdocs/buta-sup.pdf*.

[380] U.S. EPA (2002) Full IRIS Summary for 1,3-butadiene (CASRN 106–99–0). Environmental Protection Agency, Integrated Risk Information System (IRIS), Research and Development, National Center for Environmental Assessment, Washington, DC, *http://www.epa.gov/iris/subst/0139.htm*.

[381] International Agency for Research on Cancer (IARC) (1999) Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 71, Re-evaluation of some organic chemicals, hydrazine and hydrogen peroxide and Volume 97 (in preparation), World Health Organization, Lyon, France.

[382] U.S. Department of Health and Human Services (2005) National Toxicology Program, 11th Report on Carcinogens, available at: *http://ntp.niehs.nih.gov/index.cfm?objectid=32BA9724–F1F6–975E–7FCE50709CB4C932*.

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[384] International Agency for Research on Cancer (IARC). 1988. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 44, Alcohol Drinking, World Health Organization, Lyon, France.

[385] U.S. Department of Health and Human Services. 2005. National Toxicology Program 11th Report on Carcinogens available at: *ntp.niehs.nih.gov/index.cfm?objectid=32BA9724-F1F6-975E-7FCE50709CB4C932*.

consumption. Effects include neurological impairment, developmental effects, cardiovascular effects, immune system depression, and effects on the liver, pancreas and reproductive system.[386] There is evidence that children prenatally exposed via mothers' ingestion of alcoholic beverages during pregnancy are at increased risk of hyperactivity and attention deficits, impaired motor coordination, a lack of regulation of social behavior or poor psychosocial functioning, and deficits in cognition, mathematical ability, verbal fluency, and spatial memory.[387 388 389 390 391 392 393 394] In some people, genetic factors influencing the metabolism of ethanol can lead to differences in internal levels of ethanol and may render some subpopulations more susceptible to risks from the effects of ethanol.

f. Formaldehyde

Since 1987, EPA has classified formaldehyde as a probable human carcinogen based on evidence in humans and in rats, mice, hamsters, and monkeys.[395] EPA is currently reviewing recently published epidemiological data. For instance, research conducted by the National Cancer Institute (NCI) found an increased risk of nasopharyngeal cancer and lymphohematopoietic malignancies such as leukemia among workers exposed to formaldehyde.[396 397] NCI is currently performing an update of these studies. A recent National Institute of Occupational Safety and Health (NIOSH) study of garment workers also found increased risk of death due to leukemia among workers exposed to formaldehyde.[398] Extended follow-up of a cohort of British chemical workers did not find evidence of an increase in nasopharyngeal or lymphohematopoietic cancers, but a continuing statistically significant excess in lung cancers was reported.[399] Recently, the IARC re-classified formaldehyde as a human carcinogen (Group 1).[400]

Formaldehyde exposure also causes a range of noncancer health effects, including irritation of the eyes (burning and watering of the eyes), nose and throat. Effects from repeated exposure in humans include respiratory tract irritation, chronic bronchitis and nasal epithelial lesions such as metaplasia and loss of cilia. Animal studies suggest that formaldehyde may also cause airway inflammation—including eosinophil infiltration into the airways. There are several studies that suggest that formaldehyde may increase the risk of asthma—particularly in the young.[401 402]

g. Naphthalene

Naphthalene is found in small quantities in gasoline and diesel fuels. Naphthalene emissions have been measured in larger quantities in both gasoline and diesel exhaust compared with evaporative emissions from mobile sources, indicating it is primarily a product of combustion. EPA released an external review draft of a reassessment of the inhalation carcinogenicity of naphthalene based on a number of recent animal carcinogenicity studies.[403] The draft reassessment completed external peer review.[404] Based on external peer review comments received, additional analyses are being undertaken. This external review draft does not represent official agency opinion and was released solely for the purposes of external peer review and public comment. Once EPA evaluates public and peer reviewer comments, the document will be revised. The National Toxicology Program listed naphthalene as ''reasonably anticipated to be a human carcinogen'' in 2004 on the basis of bioassays reporting clear evidence of carcinogenicity in rats and some evidence of carcinogenicity in mice.[405] California EPA has released a new risk assessment for naphthalene, and the IARC has reevaluated naphthalene and re-classified it as Group 2B: possibly carcinogenic to humans.[406] Naphthalene also causes a number of chronic non-cancer effects in animals, including abnormal cell changes and growth in respiratory and nasal tissues.[407]

h. Peroxyacetyl Nitrate (PAN)

Peroxyacetyl nitrate (PAN) has not been evaluated by EPA's IRIS program. Information regarding the potential carcinogenicity of PAN is limited. As noted in the EPA air quality criteria

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[400] International Agency for Research on Cancer (IARC). 2006. Formaldehyde, 2-Butoxyethanol and 1-tert-Butoxypropan-2-ol. Volume 88. (in preparation), World Health Organization, Lyon, France.

[401] Agency for Toxic Substances and Disease Registry (ATSDR). 1999. Toxicological profile for Formaldehyde. Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service. *http://www.atsdr.cdc.gov/toxprofiles/tp111.html.*

[402] WHO (2002) Concise International Chemical Assessment Document 40: Formaldehyde. Published under the joint sponsorship of the United Nations Environment Programme, the International Labour Organization, and the World Health Organization, and produced within the framework of the Inter-Organization Programme for the Sound Management of Chemicals. Geneva.

[403] U.S. EPA. 2004. Toxicological Review of Naphthalene (Reassessment of the Inhalation Cancer Risk), Environmental Protection Agency, Integrated Risk Information System, Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at *http://www.epa.gov/iris/subst/0436.htm.*

[404] Oak Ridge Institute for Science and Education. (2004). External Peer Review for the IRIS Reassessment of the Inhalation Carcinogenicity of Naphthalene. August 2004. *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=84403.*

[405] National Toxicology Program (NTP). (2004). 11th Report on Carcinogens. Public Health Service, U.S. Department of Health and Human Services, Research Triangle Park, NC. Available from: *http://ntp-server.niehs.nih.gov.*

[406] International Agency for Research on Cancer (IARC). (2002). Monographs on the Evaluation of the Carcinogenic Risk of Chemicals for Humans. Vol. 82, Lyon, France.

[407] U.S. EPA. 1998. Toxicological Review of Naphthalene, Environmental Protection Agency, Integrated Risk Information System, Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at *http://www.epa.gov/iris/subst/0436.htm.*

document for ozone and related photochemical oxidants, cytogenetic studies indicate that PAN is not a potent mutagen, clastogen (a compound that can cause breaks in chromosomes), or DNA-damaging agent in mammalian cells either in vivo or in vitro. Some studies suggest that PAN may be a weak bacterial mutagen at high concentrations much higher than exist in present urban atmospheres.[408]

Effects of ground-level smog causing intense eye irritation have been attributed to photochemical oxidants, including PAN.[409] Animal toxicological information on the inhalation effects of the non-ozone oxidants has been limited to a few studies on PAN. Acute exposure to levels of PAN can cause changes in lung morphology, behavioral modifications, weight loss, and susceptibility to pulmonary infections. Human exposure studies indicate minor pulmonary function effects at high PAN concentrations, but large inter-individual variability precludes definitive conclusions.[410]

i. Other Air Toxics

In addition to the compounds described above, other compounds in gaseous hydrocarbon and PM emissions from vehicles will be affected by today's proposed action. Mobile source air toxic compounds that will potentially be impacted include ethylbenzene, polycyclic organic matter, propionaldehyde, toluene, and xylene. Information regarding the health effects of these compounds can be found in EPA's IRIS database.[411]

F. Environmental Effects of Criteria and Air Toxic Pollutants

In this section we discuss some of the environmental effects of PM and its precursors, such as visibility impairment, atmospheric deposition, and materials damage and soiling, as well as environmental effects associated with the presence of ozone in the ambient air, such as impacts on plants, including trees, agronomic crops and urban ornamentals, and environmental effects associated with air toxics.

1. Visibility

Visibility can be defined as the degree to which the atmosphere is transparent to visible light.[412] Airborne particles degrade visibility by scattering and absorbing light. Visibility is important because it has direct significance to people's enjoyment of daily activities in all parts of the country. Individuals value good visibility for the well-being it provides them directly, where they live and work, and in places where they enjoy recreational opportunities. Visibility is also highly valued in natural areas such as national parks and wilderness areas and special emphasis is given to protecting visibility in these areas. For more information on visibility see the final 2004 PM AQCD as well as the 2005 PM Staff Paper.[413] [414]

EPA is pursuing a two-part strategy to address visibility. First, to address the welfare effects of PM on visibility, EPA has set secondary $PM_{2.5}$ standards which act in conjunction with the establishment of a regional haze program. In setting this secondary standard EPA has concluded that $PM_{2.5}$ causes adverse effects on visibility in various locations, depending on PM concentrations and factors such as chemical composition and average relative humidity. Second, section 169 of the Clean Air Act provides additional authority to address existing visibility impairment and prevent future visibility impairment in the 156 national parks, forests and wilderness areas categorized as mandatory class I federal areas (62 FR 38680–81, July 18, 1997).[415] In July 1999 the regional haze rule (64 FR 35714) was put in place to protect visibility in mandatory class I federal areas. Visibility can be said to be impaired in both $PM_{2.5}$ nonattainment areas and mandatory class I federal areas.

2. Atmospheric Deposition

Wet and dry deposition of ambient particulate matter delivers a complex mixture of metals (e.g., mercury, zinc, lead, nickel, aluminum, cadmium), organic compounds (e.g., POM, dioxins, furans) and inorganic compounds (e.g., nitrate, sulfate) to terrestrial and aquatic ecosystems. The chemical form of the compounds deposited depends on a variety of factors including ambient conditions (e.g., temperature, humidity, oxidant levels) and the sources of the material. Chemical and physical transformations of the particulate compounds occur in the atmosphere as well as the media onto which they deposit. These transformations in turn influence the fate, bioavailability and potential toxicity of these compounds. Atmospheric deposition has been identified as a key component of the environmental and human health hazard posed by several pollutants including mercury, dioxin and PCBs.[416]

Adverse impacts on water quality can occur when atmospheric contaminants deposit to the water surface or when material deposited on the land enters a waterbody through runoff. Potential impacts of atmospheric deposition to waterbodies include those related to both nutrient and toxic inputs. Adverse effects to human health and welfare can occur from the addition of excess particulate nitrate nutrient enrichment, which contributes to toxic algae blooms and zones of depleted oxygen, which can lead to fish kills, frequently in coastal waters. Particles contaminated with heavy metals or other toxins may lead to the ingestion of contaminated fish, ingestion of contaminated water, damage to the marine ecology, and limits to recreational uses. Several studies have been conducted in U.S. coastal waters and in the Great Lakes Region in which the role of ambient PM deposition and runoff is

[408] U.S. EPA. 2006. Air Quality Criteria for Ozone and Related Photochemical Oxidants (Ozone CD). Research Triangle Park, NC: National Center for Environmental Assessment; report no. EPA/600/R–05/004aF–cF.3v. page 5–78. Available at *http://cfpub.epa.gov/ncea/*.

[409] U.S. EPA. 2006. Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final). U.S. Environmental Protection Agency, Washington, DC, EPA 600/R–05/004aF–cF. pages 5–63. This document is available in Docket EPA–HQ–OAR–2005–0161. This document may be accessed electronically at: *http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_cr_cd.html.*

[410] U.S. EPA. 2006. Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final). U.S. Environmental Protection Agency, Washington, DC, EPA 600/R–05/004aF–cF. pages 5–78. This document is available in Docket EPA–HQ–OAR–2005–0161. This document may be accessed electronically at: *http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_cr_cd.html.*

[411] U.S. EPA. Integrated Risk Information System (IRIS) database is available at: *www.epa.gov/iris.*

[412] National Research Council, 1993. Protecting Visibility in National Parks and Wilderness Areas. National Academy of Sciences Committee on Haze in National Parks and Wilderness Areas. National Academy Press, Washington, DC. This document is available in Docket EPA–HQ–OAR–2005–0161. This book can be viewed on the National Academy Press Web site at *http://www.nap.edu/books/0309048443/html/*.

[413] U.S. EPA (2004) Air Quality Criteria for Particulate Matter (Oct 2004), Volume I Document No. EPA600/P–99/002aF and Volume II Document No. EPA600/P–99/002bF. This document is available in Docket EPA–HQ–OAR–2005–0161.

[414] U.S. EPA (2005) Review of the National Ambient Air Quality Standard for Particulate Matter: Policy Assessment of Scientific and Technical Information, OAQPS Staff Paper. EPA–452/R–05–005. This document is available in Docket EPA–HQ–OAR–2005–0161.

[415] These areas are defined in CAA section 162 as those national parks exceeding 6,000 acres, wilderness areas and memorial parks exceeding 5,000 acres, and all international parks which were in existence on August 7, 1977.

[416] U.S. EPA (2000) Deposition of Air Pollutants to the Great Waters: Third Report to Congress. Office of Air Quality Planning and Standards. EPA–453/R–00–0005. This document is available in Docket EPA–HQ–OAR–2005–0161.

investigated.[417 418 419 420 421] In addition, the process of acidification affects both freshwater aquatic and terrestrial ecosystems. Acid deposition causes acidification of sensitive surface waters. The effects of acid deposition on aquatic systems depend largely upon the ability of the ecosystem to neutralize the additional acid. As acidity increases, aluminum leached from soils and sediments, flows into lakes and streams and can be toxic to both terrestrial and aquatic biota. The lower pH concentrations and higher aluminum levels resulting from acidification make it difficult for some fish and other aquatic organisms to survive, grow, and reproduce.

Adverse impacts on soil chemistry and plant life have been observed for areas heavily influenced by atmospheric deposition of nutrients, metals and acid species, resulting in species shifts, loss of biodiversity, forest decline and damage to forest productivity. Potential impacts also include adverse effects to human health through ingestion of contaminated vegetation or livestock (as in the case for dioxin deposition), reduction in crop yield, and limited use of land due to contamination. Research on effects of acid deposition on forest ecosystems has come to focus increasingly on the biogeochemical processes that affect uptake, retention, and cycling of nutrients within these ecosystems. Decreases in available base cations from soils are at least partly attributable to acid deposition. Base cation depletion is a cause for concern because of the role these ions play in acid neutralization and because calcium, magnesium and potassium are essential nutrients for plant growth and physiology. Changes in the relative proportions of these nutrients, especially in comparison with aluminum concentrations, have been associated with declining forest health.

[417] U.S. EPA (2004) National Coastal Condition Report II. Office of Research and Development/Office of Water. EPA–620/R–03/002. This document is available in Docket EPA–HQ–OAR–2005–0161.

[418] Gao, Y., E.D. Nelson, M.P. Field, et al. 2002. Characterization of atmospheric trace elements on $PM_{2.5}$ particulate matter over the New York-New Jersey harbor estuary. *Atmos. Environ.* 36: 1077–1086.

[419] Kim, G., N. Hussain, J.R. Scudlark, and T.M. Church. 2000. Factors influencing the atmospheric depositional fluxes of stable Pb, 210Pb, and 7Be into Chesapeake Bay. *J. Atmos. Chem.* 36: 65–79.

[420] Lu, R., R.P. Turco, K. Stolzenbach, et al. 2003. Dry deposition of airborne trace metals on the Los Angeles Basin and adjacent coastal waters. *J. Geophys. Res.* 108(D2, 4074): AAC 11–1 to 11–24.

[421] Marvin, C.H., M.N. Charlton, E.J. Reiner, et al. 2002. Surficial sediment contamination in Lakes Erie and Ontario: A comparative analysis. *J. Great Lakes Res.* 28(3): 437–450.

The deposition of airborne particles can reduce the aesthetic appeal of buildings and culturally important articles through soiling and can contribute directly (or in conjunction with other pollutants) to structural damage by means of corrosion or erosion.[422] Particles affect materials principally by promoting and accelerating the corrosion of metals, by degrading paints, and by deteriorating building materials such as concrete and limestone. Particles contribute to these effects because of their electrolytic, hygroscopic, and acidic properties and their ability to adsorb corrosive gases (principally sulfur dioxide). The rate of metal corrosion depends on a number of factors, including: The deposition rate and nature of the pollutant; the influence of the metal protective corrosion film; the amount of moisture present; variability in the electrochemical reactions; the presence and concentration of other surface electrolytes; and the orientation of the metal surface.

3. Plant and Ecosystem Effects of Ozone

Ozone contributes to many environmental effects, with impacts to plants and ecosystems being of most concern. Ozone can produce both acute and chronic injury in sensitive species depending on the concentration level and the duration of the exposure. Ozone effects also tend to accumulate over the growing season of the plant, so that even lower concentrations experienced for a longer duration have the potential to create chronic stress on vegetation. Ozone damage to plants includes visible injury to leaves and a reduction in food production through impaired photosynthesis, both of which can lead to reduced crop yields, forestry production, and use of sensitive ornamentals in landscaping. In addition, the reduced food production in plants and subsequent reduced root growth and storage below ground can result in other, more subtle plant and ecosystems impacts. These include increased susceptibility of plants to insect attack, disease, harsh weather, interspecies competition and overall decreased plant vigor. The adverse effects of ozone on forest and other natural vegetation can potentially lead to species shifts and loss from the affected ecosystems, resulting in a loss or reduction in associated ecosystem goods and services. Last, visible ozone injury to leaves can result in a loss of aesthetic value in areas of special scenic significance like national parks and wilderness areas. The final 2006 Ozone Air Quality Criteria Document presents more detailed information on ozone effects on vegetation and ecosystems.

[422] U.S. EPA (2005). Review of the National Ambient Air Quality Standards for Particulate Matter: Policy Assessment of Scientific and Technical Information, OAQPS Staff Paper. This document is available in Docket EPA–HQ–OAR–2005–0161.

4. Welfare Effects of Air Toxics

Fuel combustion emissions contribute to ambient levels of pollutants that contribute to adverse effects on vegetation. PAN is a well-established phytotoxicant causing visible injury to leaves that can appear as metallic glazing on the lower surface of leaves with some leafy vegetables exhibiting particular sensitivity (e.g., spinach, lettuce, chard).[423 424 425] PAN has been demonstrated to inhibit photosynthetic and non-photosynthetic processes in plants and retard the growth of young navel orange trees.[426 427] In addition to its oxidizing capability, PAN contributes nitrogen to forests and other vegetation via uptake as well as dry and wet deposition to surfaces. As noted in Section X, nitrogen deposition can lead to saturation of terrestrial ecosystems and research is needed to understand the impacts of excess nitrogen deposition experienced in some areas of the country on water quality and ecosystems.[428]

Volatile organic compounds (VOCs), some of which are considered air toxics, have long been suspected to play a role in vegetation damage.[429] In laboratory experiments, a wide range of tolerance to VOCs has been observed.[430] Decreases in harvested seed pod weight

[423] Nouchi I, S Toyama. 1998. Effects of ozone and peroxyacetyl nitrate on polar lipids and fatty acids in leaves of morning glory and kidney bean. Plant Physiol. 87:638–646.

[424] Oka E, Y Tagami, T Oohashi, N Kondo. 2004. A physiological and morphological study on the injury caused by exposure to the air pollutant, peroxyacetyl nitrate (PAN), based on the quantitative assessment of the injury. J Plant Res. 117:27–36.

[425] Sun E-J, M-H Huang. 1995. Detection of peroxyacetyl nitrate at phytotoxic level and its effects on vegetation in Taiwan. Atmos. Env. 29:2899–2904.

[426] Koukol J, WM Dugger, Jr., RL Palmer. 1967. Inhibitory effect of peroxyacetyl nitrate on cyclic photophosphorylation by chloroplasts from black valentine bean leaves. Plant Physiol. 42:1419–1422.

[427] Thompson CR, G Kats. 1975. Effects of ambient concentrations of peroxyacetyl nitrate on navel orange trees. Env. Sci. Technol. 9:35–38.

[428] Bytnerowicz A, ME Fenn. 1995. Nitrogen deposition in California forests: A Review. Environ. Pollut. 92:127–146.

[429] U.S. EPA. 1991. Effects of organic chemicals in the atmosphere on terrestrial plants. EPA/600/3–91/001.

[430] Cape JN, ID Leith, J Binnie, J Content, M Donkin, M Skewes, DN Price, AR Brown, AD Sharpe. 2003. Effects of VOCs on herbaceous plants in an open-top chamber experiment. Environ. Pollut. 124:341–343.

have been reported for the more sensitive plants, and some studies have reported effects on seed germination, flowering and fruit ripening. Effects of individual VOCs or their role in conjunction with other stressors (e.g., acidification, drought, temperature extremes) have not been well studied. In a recent study of a mixture of VOCs including ethanol and toluene on herbaceous plants, significant effects on seed production, leaf water content and photosynthetic efficiency were reported for some plant species.[431]

Research suggests an adverse impact of vehicle exhaust on plants, which has in some cases been attributed to aromatic compounds and in other cases to nitrogen oxides.[432 433 434] The impacts of VOCs on plant reproduction may have long-term implications for biodiversity and survival of native species near major roadways. Most of the studies of the impacts of VOCs on vegetation have focused on short-term exposure and few studies have focused on long-term effects of VOCs on vegetation and the potential for metabolites of these compounds to affect herbivores or insects.

VIII. Impacts on Cost of Renewable Fuels, Gasoline, and Diesel

We have assessed the impacts of the renewable fuel volumes required by EISA on their costs and on the costs of the gasoline and diesel fuels into which the renewable fuels will be blended. More details of feedstock costs are addressed in Section X.A.

A. Renewable Fuel Production Costs

1. Ethanol Production Costs

a. Corn Ethanol

A significant amount of work has been done in the last decade surveying and modeling the costs involved in producing ethanol from corn in order to serve business and investment purposes as well as to try to educate energy policy decisions. Corn ethanol costs for our work were estimated using models developed and maintained by USDA. Their work has been described in a peer-reviewed journal paper on cost modeling of the dry-grind corn ethanol process, and compares well with cost information found in surveys of existing plants.[435 436]

For our policy case scenario, we used corn prices of $3.34/bu in 2022 with corresponding DDGS prices of $139.78/ton (all 2006$). These estimates are taken from agricultural economics modeling work done for this proposal using the Forestry and Agricultural Sector Optimization Model (*see* Section IX.A).

For natural gas-fired ethanol production producing dried co-product (currently describes the largest fraction of the industry), in the policy case corn feedstock minus DDGS sale credit represents about 57% of the final per-gallon cost, while utilities, facility, and labor comprise about 22%, 11%, and 4%, respectively. Thus, the cost of ethanol production is most sensitive to the prices of corn and the primary co-product, DDGS, and relatively insensitive to economy of scale over the range of plant sizes typically seen (40–100 MMgal/yr).

We expect that several process fuels will be used to produce corn ethanol (see DRIA Section 1.4), which are presented by their projected 2022 volume production share in Table VIII.A.1–1a and cost impacts for each in Table VIII.A.1–1b.[437] We request comment on the projected mix of plant fuel sources in the future as well as the cost impacts of various technologies.

TABLE VIII.A.1–1a—PROJECTED 2022 BREAKDOWN OF FUEL TYPES USED TO ESTIMATE PRODUCTION COST OF CORN ETHANOL, PERCENT SHARE OF TOTAL PRODUCTION VOLUME

Plant type	Fuel type				Total by plant type
	Biomass (percent)	Coal (percent)	Natural gas (percent)	Biogas (percent)	All fuels (percent)
Coal/Biomass Boiler	11	0			11
Coal/Biomass Boiler + CHP	10	4			14
Natural Gas Boiler			49	14	63
Natural Gas Boiler + CHP			12		12
Total by Fuel Type	21	4	61	14	100

TABLE VIII.A.1–1b—PROJECTED 2022 BREAKDOWN OF COST IMPACTS BY FUEL TYPE USED IN ESTIMATING PRODUCTION COST OF CORN ETHANOL, DOLLARS PER GALLON RELATIVE TO NATURAL GAS BASELINE

Plant type	Fuel type				Total by plant type
	Biomass [a]	Coal	Natural gas	Biogas [b]	All fuels
Coal/Biomass Boiler	−$0.02	−$0.02			
Coal/Biomass Boiler + CHP	+$0.14	+$0.14			
Natural Gas Boiler			baseline	+$0.00	

[431] Cape JN, ID Leith, J Binnie, J Content, M Donkin, M Skewes, DN Price, AR Brown, AD Sharpe. 2003. Effects of VOCs on herbaceous plants in an open-top chamber experiment. Environ. Pollut. 124:341–343.

[432] Viskari E-L. 2000. Epicuticular wax of Norway spruce needles as indicator of traffic pollutant deposition. Water, Air, and Soil Pollut. 121:327–337.

[433] Ugrekhelidze D, F Korte, G Kvesitadze. 1997. Uptake and transformation of benzene and toluene by plant leaves. Ecotox. Environ. Safety 37:24–29.

[434] Kammerbauer H, H Selinger, R Rommelt, A Ziegler-Jons, D Knoppik, B Hock. 1987. Toxic components of motor vehicle emissions for the spruce Pciea abies. Environ. Pollut. 48:235–243.

[435] Kwaitkowski, J.R., Macon, A., Taylor, F., Johnston, D.B.; *Industrial Crops and Products* 23 (2006) 288–296.

[436] Shapouri, H., Gallagher, P.; USDA's 2002 Ethanol Cost-of-Production Survey (published July 2005).

[437] Projected fuel mix was taken from Mueller, S., Energy Research Center at the University of Chicago; An Analysis of the Projected Energy Use of Future Dry Mill Corn Ethanol Plants (2010–2030); cost estimates were derived from modifications to the USDA process models. We are aware that the cost impacts of CHP are likely overestimated here and will be revised in the final rulemaking.

TABLE VIII.A.1–1b—PROJECTED 2022 BREAKDOWN OF COST IMPACTS BY FUEL TYPE USED IN ESTIMATING PRODUCTION COST OF CORN ETHANOL, DOLLARS PER GALLON RELATIVE TO NATURAL GAS BASELINE—Continued

Plant type	Fuel type				Total by plant type
	Biomass [a]	Coal	Natural gas	Biogas [b]	All fuels
Natural Gas Boiler + CHP			+$0.16		
Total by Fuel Type					$0.04

[a] Assumes biomass has same plant-delivered cost as coal.
[b] Assumes biogas has same plant-delivered cost as natural gas.

Based on energy prices from EIA's Annual Energy Outlook (AEO) 2008 baseline case ($53/bbl crude oil), we arrive at a production cost of $1.49/gal. In the case of EIA's high price scenario ($92/bbl crude), this figure increases by 6 cents per gallon. More details on the ethanol production cost estimates can be found in Chapter 4 of the DRIA. This estimate represents the full cost to the plant operator, including purchase of feedstocks, energy required for operations, capital depreciation, labor, overhead, and denaturant, minus revenue from sale of co-products. The capital cost for a 65 MMgal/yr natural gas fired dry mill plant is estimated at $89MM (this the projected average size of such plants in 2022). Similarly, coal and biomass fired plants were assumed to be 110 MGY in capacity, with an estimated capital cost of $200MM.[438] On average, ethanol produced in a facility using coal or biomass as a primary energy source results in a per-gallon cost $0.02/gal lower compared to production using natural gas.

In this cost estimation work, we did not assume any pelletizing of DDGS. Pelletizing is expected to improve ease of shipment to more distant markets, which may become more important at the larger volumes projected for the future. However, while many in industry are aware of this technology, those we spoke with are not employing it in their plants, and do not expect widespread use in the foreseeable future. According to USDA's model, pelletizing adds $0.035/gal to the ethanol production cost. We request comment on whether pelletizing should be included in our program cost estimates.

In support of our biodiesel and renewable diesel volume feasibility estimates, we included recovery of corn oil from distillers' grains streams in our ethanol production cost estimates at a rate of 37% of ethanol production by 2022.[439] According to economic analyses done by USDA based on the GS Cleantech corn oil extraction process, the capital cost to install the system for a 50 MMgal/yr ethanol plant is approximately $6 million. The system is capable of extracting about one third of the corn oil entering the plant, and produces a low-quality corn oil co-product stream. In our analysis, we assumed the value of this additional co-product to be 70% that of soy oil (the same as yellow grease, $0.27/lb), resulting in a credit per gallon of ethanol of $0.04 for a 50 MMgal/yr plant operating such a system.

Note that the ethanol production cost given here does not account for any subsidies on production or sale of ethanol, and is independent of the market price of ethanol.

b. Cellulosic Ethanol

i. Feedstock Costs

Cellulosic Feedstock Costs

To estimate the cost of producing cellulosic biofuels, it was first necessary to estimate the cost of harvesting, storing, processing and transporting the feedstocks to the biofuel production facilities. Ethanol or other cellulosic biofuels can be produced from crop residues such as corn stover, wheat, rice, oat, and barley straw, sugar cane bagasse, and sorghum, from other cellulosic plant matter such as forest thinnings and forest-fuel removal, pulping residues, and from the cellulosic portions of municipal solid waste (MSW). Currently, there are no energy crops such as switchgrass nor short rotation woody crops (SRWC poplars, etc.) grown specifically for energy production.

Our feedstock supply analysis projected that crop residue, primarily corn stover, will be the most abundant of the cellulosic feedstocks, comprising about 61% of the total biomass feedstock inventory. Forest residues make up about 25% of the total, and MSW makes up the remaining 14%. At present, there are no commercial sized cellulosic ethanol plants in the U.S. Likewise, there are no commercially proven, fully-integrated feedstock supply systems dedicated to providing any of the feedstocks we mentioned to ethanol facilities of any size, although certain biomass is harvested for other purposes. For this reason, our feedstock cost estimates are projections and not based on any existing market data.

Our feedstock costs include an additional preprocessing cost that many other feedstock cost estimates do not include—thus our costs may seem higher. We used biofuel plant cost estimates provided by NREL which no longer includes the cost for finely grinding the feedstock prior to feeding it to the biofuel plant. Thus, our feedstock costs include an $11 per dry ton cost to account for the costs of this grinding operation, regardless of whether this operation occurs in the field or at the plant gate.

Crop Residue and Energy Crops

Crop residue harvest is currently a secondary harvest; that is they are harvested or gathered only after the prime crop has been harvested. In most northern areas, the harvest periods will be short due to the onset of winter weather. In some cases, it may be necessary to gather a full year's worth of residue within just a few weeks. Consequently, to accomplish this hundreds of pieces of farm equipment will be required for a few weeks each year to complete a harvest. Winter conditions in the South make it somewhat easier to extend the harvest periods; in some cases, it may be possible to harvest a residue on an as needed basis.

During the corn grain harvest, generally only the cob and the leaves above the cob are taken into the harvester. Thus, the stover harvest would likely require some portion of the

[438] Capital costs for a natural gas fired plant were taken from USDA cost model; incremental costs to use coal as the primary energy source were derived from conversations with ethanol plant construction contractors.

[439] Although some oil extraction may be done as front-end fractionation of the kernel, we believe the majority will be produced via separation from distillers' grains streams. For more discussion of corn oil extraction and fractionation, *see* Chapter 4 of the DRIA.

standing-stalks be mowed or shredded, following which the entire residue, including that discharged from the combine residue-spreader, would need to be raked. Balers, likely a mix of large round and large square balers, would follow the rakes. The bales would then be removed from the field, usually to the field-side in the first operation of the actual harvest, following which they would then be hauled to a satellite facility for intermediate storage. For our analysis we assumed that bales would then be hauled by truck and trailer to the processing plant on an as needed basis.

The small grain straws (wheat, rice, oats, barley, sorghum) are cut near the ground at the time of grain harvest and thus likely won't require further mowing or shredding. They will likely need to be raked into a windrow prior to baling. Because small grain straws have been baled and stored for many years, we don't expect unusual requirements for handling these residues. Their harvest and storage costs will likely be less than those for corn stover, but their overall quantity is much less than corn stover (corn stover makes up about 71% of all the crop residues), so we don't expect their lower costs to have, individually or collectively, a huge effect on the overall feedstock costs. Thus, we project that for several years, the feedstock costs will be largely a function of the cost to harvest, store, and haul corn stover.

For the crop residues, we relied on the FASOM agricultural cost model for farm harvesting and collection costs. FASOM estimates it would cost $33 per dry ton to mow, rake, bale, and field haul the bales and replace nutrients. We added $10 per dry ton as a farmer payment, which we believe is a necessary reimbursement to farmers to cover their costs associated with this additional harvest. Thus, $43 per dry ton covers the cost of making the crop residue available at the farm gate. This farm gate cost could be lower if new equipment is developed that would allow the farmer to harvest the corn stover at the same time as the corn. We also conducted our own independent analysis of the farm gate feedstock costs for corn stover, and our farm gate cost estimate for stover feedstock is very similar to FASOM's. For the steps involved in moving the corn stover from the farm gate to the cellulosic ethanol plant, we relied upon our own cost analysis. Our cost analysis estimates that an additional $32 per dry ton would be required to haul the bales to satellite storage, pay for the storage facilities, and grind the residue. Because of the low density of corn stover and other crop residues, we estimate that 60 or more secondary storage sites would be necessary to minimize the combined transportation and storage costs for a 100 million gallon per year plant. We estimated it would cost about $14 per dry ton to haul the feedstock from the satellite storage to the processing plant. Adding up all the costs, corn stover is estimated to cost $88 per dry ton delivered to the cellulosic biofuel plant. A more detailed discussion of our corn stover feedstock cost analysis is contained in Chapter 4.1 of the DRIA.

Energy crops such as switchgrass and miscanthus would be harvested, baled, stored and transported very similar to crop residues. Because of their higher production density per acre, though, we would expect that the ''farm gate'' costs to be slightly lower than crop residues (we estimate the costs to be about $1 per dry ton lower). Also, the higher production density would allow for fewer secondary storage facilities compared to crop residue and a shorter transportation distance. For example, we estimate that switchgrass would require less than 30 secondary storage facilities which would help to lower the feedstock costs for a 100 million gallon per year plant compared to crop residues. As a result the secondary storage and transportation costs are estimated to be $9 per ton lower than crop residue such as corn stover. Thus, we estimate that cellulosic feedstock costs sourced from switchgrass would be about $78 per dry ton. Chapter 4.1 of the DRIA contains a more in-depth discussion of the feedstock costs for energy crops such as switchgrass.

Forestry Residue

Harvest and transport costs for woody biomass in its different forms vary due to tract size, tree species, volumes removed, distance to the wood-using/storage facility, terrain, road condition, and other many other considerations. There is a significant variation in these factors within the United States, so timber harvest and delivery systems must be designed to meet constraints at the local level. Harvesting costs also depend on the type of equipment used, season in which the operation occurs, along with a host of other factors. Much of the forest residue is already being harvested by logging operations, or is available from milling operations. However, the smaller branches and smaller trees proposed to be used for biofuel production are not collected for their lumber so they are normally left behind. Thus, this forest residue would have to be collected and transported out of the forest, and then most likely chipped before transport to the biofuel plant.

In general, most operators in the near future would be expected to chip at roadside in the forest, blowing the chips directly into a chip van. When the van is full it will be hauled to an end user's facility and a new van will be moved into position at the chipper. The process might change in the future as baling systems become economically feasible or as roll-off containers are proven as a way to handle logging slash. At present, most of the chipping for biomass production is done in connection with forest thinning treatments as part of a forest fire prevention strategy. The major problem associated with collecting logging residues and biomass from small trees is handling the material in the forest before it gets to the chipper. Specially-built balers and roll-off containers offer some promise to reduce this cost. Whether the material is collected from a forest thinning operation or a commercial logging operation, chips from residues will be dirty and will require screening or some type of filtration at the end-user's facility.[440]

Results from a study in South Georgia show that under the right conditions, a small chipper could be added to a larger operation to obtain additional chip production without adversely impacting roundwood production, and that the chips could be produced from limbs and tops of harvested trees at costs ranging from $11 per ton and up. Harvesting understory (the layer formed by grasses, shrubs, and small trees under the canopy of larger trees and plants) for use in making fuel chips was estimated to be about $1 per ton more expensive.

Per-ton costs decrease as the volume chipped increases per acre. Some estimates suggest that if no more than 10 loads of roundwood are produced before a load of chips is made, that chipper-modified system could break even. Cost projections suggest that removing only limbs and tops may be marginal in terms of cost since one load of chips is produced for about every 15 loads of roundwood.

Instead of conducting our own detailed cost estimate for making forest residue chips available at the edge of the harvested forests, we instead relied upon the expertise of the U.S. Forest Service. The U.S. Forest Service provided us a cost curve for different categories of forest residue, including logging residue, other removals (i.e., clearing trees for new building construction), timberland trimmings

[440] Personal Communication, Eini C. Lowell, Research Scientist, USDA Forest Service.

(forest fire prevention strategy) and mill residues. They recommended that we choose $45 per dry ton as the price point for our cost analysis. This seemed reasonable since this price point was roughly the same as the farm gate crop residue discussed above, and so we used this price point for our analysis. Assuming that the wood chips would be ground further in the field adds an additional $11 per dry ton to the feedstock cost.

Delivery of woody biomass from the harvesting site to a conversion facility, like delivery of more conventional forest products, accounts for a significant portion of the delivered cost. In fact, transportation of wood fiber (including hauling within the forest) accounts for about 25 to 50% of the total delivered costs and highly depends on fuel prices, haul distance, material moisture content, and vehicle capacity and utilization. Also, beyond a certain distance, transportation becomes the limiting factor and the costs become directly proportional to haul distance.[441] Based on our own cost analysis, we anticipate that hauling woody biomass to plant will cost about $14 per ton, for a total delivered price of about $70 per dry ton. Chapter 4.1 of the DRIA contains a more detailed discussion on the feedstock costs for forest residue.

Municipal Solid Waste

Millions of tons of municipal solid waste (MSW) continue to be disposed of in landfills across the country, despite recent large gains in waste reduction and diversion. The biomass fraction of this total stream represents a potentially significant resource for renewable energy (including electricity and biofuels). Because this waste material is already being generated, collected and transported (it would only need to be transported to a different location), its use is likely to be less expensive than other cellulosic feedstocks. One important difficulty facing those who plan to use MSW fractions for fuel production is that in many places, even today, MSW is a mixture of all types of wastes, including biomaterials such as animal fats and grease, tin, iron, aluminum, and other metals, painted woods, plastics, and glass. Many of these materials can't be used in biochemical and thermochemical ethanol production, and, in fact, would inflate the transportation costs, impede the operations at the cellulosic ethanol plant and cause an expensive waste stream for biofuel producers.

Thus, accessing sorted MSW would likely be a requirement for firms planning on using MSW for producing cellulosic biofuels. In a confidential conversation, a potential producer who plans to use MSW to produce ethanol indicated that their plant plans are based on obtaining cellulosic biowaste which has already been sorted at the waste source (e.g., at the curbside, where the refuse hauler picks up waste already sorted by the generating home-owner or business). For example, in a tract of homes, one refuse truck would pick up glass, plastic, and perhaps other types of waste destined for a specific disposal depot, whereas a different truck would follow to pick up wood, paper, and other cellulosic materials to be hauled to a depot that supplies an ethanol plant. However, only a small fraction of the MSW generated today is sorted at the curbside.

Another alternative would be to sort the waste either at a sorting facility, or at the landfill, prior to dumping. There are two prominent options here. The first is that there is no sorting at the waste creation site, the home or business, and thus a single waste stream must be sorted at the facility. This operation would likely be done by hand or by automated equipment at the facility. To do so by hand is very labor intensive and somewhat slower than using an automated system. In most cases the 'by-hand' system produces a slightly cleaner stream, but the high cost of labor usually makes the automated system more cost-effective. Perhaps the best approach for low cost and a clean stream is the combination of hand sorting with automated sorting.

The third option is a combination of the two which requires that there is at least some sorting at the home or business which helps to prevent contamination of the waste material, but then the final sorting occurs downstream at a sorting site, or at the landfill.

We have little data and few estimates for the cost to sort MSW. One estimate generated by our Office of Solid Waste for a combination of mechanically and manually sorting a single waste stream downstream of where the waste is generated puts the cost in the $20 to $30 per ton range. There is a risk, though, that the waste stream could still be contaminated and this would increase the cost of both transporting the material and using this material at the biofuel plant due to the toxic ash produced which would require disposal at a toxic waste facility. If a less contaminated stream is desired it would probably require sorting at the generation site—the home or business—which would likely be more costly since many more people in society would then have to be involved and special trucks would need to be used. Also, widespread participation is difficult when a change in human behavior is required as some may not be so willing to participate. Offering incentives could help to speed the transition to curbside recycling (i.e., charging a fee for nonsorted waste, or paying a small amount for sorted tree trimmings and construction and demolition waste). Assuming that curbside sorting is involved, at least in a minor way, total sorting costs might be in the $30 to $40 per ton range. We request comment on the costs incurred for sorting cellulosic material from the rest of MSW waste.

These sorting costs would be offset by the cost savings for not disposing of the waste material. Most landfills charge tipping fees, the cost to dump a load of waste into a landfill. In the United States, the national average nominal tipping fee increased fourfold from 1985 to 2000. The real tipping fee almost doubled, up from a national average (in 1997 dollars) of about $12 per ton in 1985 to just over $30 in 2000. Equally important, it is apparent that the tipping fees are much higher in densely populated regions and for areas along the U.S. coast. For example, in 2004, the tipping fees were $9 per ton in Denver and $97 per ton in Spokane. Statewide averages also varied widely, from $8 a ton in New Mexico to $75 in New Jersey. Tipping fees ranged from $21 to 98 per ton in 2006 for MSW and $18/ton to $120/ton for construction and demolition waste. It is likely that the tipping fees are highest for contaminated waste that requires the disposal of the waste in more expensive waste sites that can accept the contaminated waste as opposed to a composting site. However, this same contaminated material would probably not be desirable to biofuel producers. Presuming that only the noncontaminated cellulosic waste (yard trimmings, building construction and demolition waste and some paper) is collected as feedstocks for biofuel plants, the handling and tipping fees are likely much lower, in the $30 per ton range.[442]

The avoidance of tipping fees, however, is a complex issue since landfills are generally not owned by municipalities anymore. Both large and small municipalities recognized their

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[441] Ashton, S.; B. Jackson; R. Schroeder. *Cost Factors in Harvesting and Transporting Woody Biomass,* 2007. Module 4: Introduction to Harvesting, Transportation, and Processing:: Fact Sheet 4.7.

[442] We plan on conducting a more thorough analysis of tipping fees by waste type for the final rulemaking.

inability to handle the new and complex solid waste regulations at a reasonable cost. Only 38 out of the 100 largest cities own their own landfills. To deal with the solid waste, large private companies built massive amounts of landfill capacity. The economic incentive is for private landfill operators to fill their landfills with garbage as early as possible to pay off their capital investment (landfill site) quickly. Also, the longer the landfill is operating the greater is its exposure to liability due to leakages and leaching. Furthermore, landfills can more cost-effectively manage the waste as the scale of the landfill is enlarged. As a result, there are fewer landfills and landfill owners, and an expansion of market share by large private waste management firms, thus decreasing the leverage a biofuel producer may have.[443] Many waste management firms have been proactive by using the waste material to produce biogas, another fuel type that would qualify under RFS2. Yet other parties interested in procuring MSW are waste-to-energy (WTE) facilities, which burn as much waste material as possible to produce electricity. These three different interests may compete for MSW for producing biofuels. This competition is desirable, resulting in lower overall cost and the production of the most cost-effective types of biofuels. We request comment on the costs avoided for diverting cellulosic material from landfills.

Once the cellulosic biomass has been sorted from the rest of MSW, it would have to be transported to the biofuels plant. Transporting is different for MSW biomass compared to forest and crop residues. Forest and crop residues are collected from forests and farms, which are both rural sites, and transported to the biofuel plant which likely is located at a rural site. The trucks which transport the forest and crop residues can be large over-the-road trucks which can average moderate speeds because of the lower amount of traffic that they experience. Conversely, MSW is being collected throughout urban areas and would have to transported through those urban areas to the plant site. If the cellulosic biomass is being collected at curbside, it would likely be collected in more conventional refuse trucks. If the plant is nearby, then the refuse trucks could transport the cellulosic biomass directly to the plant. However, if the plant is located far away from a portion of the urban area, then the refuse trucks would probably have to be offloaded to more conventional over-the-road trucks with sizable trailers to make transport more cost-effective. We estimate that the cost to transport the cellulosic biomass sourced from MSW to the biofuel plant be $15 per ton.

A significant advantage of MSW over other cellulosic biomass is that it can be generated year-round in many parts of the U.S. If a steady enough stream of this material is available, then secondary storage would not be necessary, thus avoiding the need to install secondary storage. We assumed that no secondary storage costs would be incurred for MSW-sourced cellulosic biomass.

The total costs for MSW-sourced cellulosic biomass is estimated to be $30 −$40 per ton for sorting costs, a savings of $30 per ton for tipping costs avoided, $15 per ton for transportation costs and $11 per ton for grinding the cellulose to prepare it as a feedstock—resulting in a total feedstock cost of $26 to $36 per ton. In our cost analysis, we assumed an average cost of $31 per ton. Chapter 4.1 of the DRIA contains a more detailed discussion of the feedstock costs for MSW.

Table VIII.A.1–2 below summarizes major cost components for each cellulosic feedstock.

TABLE VIII.A.1–2—SUMMARY OF CELLULOSIC FEEDSTOCK COSTS

[$53/ton crude oil costs]

Ag residue	Switchgrass	Forest residue	MSW
60% of total feedstock	1% of total feedstock	25% of total feedstock	14% of total feedstock
Mowing, Raking, Baling, Hauling, Nutrients and Farmer Payment $43/ton.	Mowing, Raking, Baling, Hauling, Nutrients and Farmer Payment $42/ton.	Harvesting, Hauling to Forest Edge, Chipping $45/ton.	Sorting, Contaminant Removal, Tipping Fees Avoided $0–$10/ton.
Hauling to Secondary Storage, Secondary Storage, Hauling to Plant $45/ton.	Hauling to Secondary Storage, Secondary Storage, Hauling to Plant $37/ton.	Grinding, Hauling to Plant $25/ton	Grinding, Hauling to Plant $26/ton.
Total $88/ton	Total $77/ton	Total $70/ton	Total Avg $31/ton.

Weighting the cellulosic feedstock costs by their supply quantities results in an average cellulosic feedstock cost of $71 per ton which we used at the reference crude oil price of $53/bbl. We estimate that this average cost increases to $76 per ton at the high crude oil price of $92/bbl due to more expensive harvesting and transportation costs.

ii. Production Costs

In this section, we discuss the cost to biochemically and thermochemically convert cellulosic feedstocks into fuel ethanol. At a DOE sponsored workshop in 2005, a DOE biochemical expert commented that the challenges of converting cellulosic biomass to ethanol are very closely linked to solving the problems associated with both the hydrolysis and the fermentation of the carbohydrates in the feedstocks. He then stated that the resistance of cellulosic feedstock to bioprocessing will remain the central problem and will likely be the limiting factor in creating an economy based on cellulosic ethanol production.[444]

Notwithstanding the fact that all cellulosic biomass is made up of some combination of cellulose, hemicellulose, lignin, and trace amounts of other organic and inorganic chemicals and minerals, there are significant differences among the molecular structures of different plants. For example, a corn stalk is relatively lighter, more porous, and much more flexible than a tree branch of similar diameter. The tree branch (in most cases) is harder or denser and less porous throughout the stem and the

[443] Osamu Sakamoto, *The Financial Feasibility Analysis of Municipal Solid Waste to Ethanol Conversion,* Michigan State University, Plan B Master Research Paper in partial fulfillment of the requirement for the degree of Master of Science, Department of Agricultural Economics, 2004

[444] *Breaking the Biological Barriers to Cellulosic Ethanol: A Joint Research Agenda,* A Research Roadmap Resulting from the Biomass to Biofuels Workshop Sponsored by the U.S. Department of Energy, December 7–9, 2005, Rockville, Maryland; DOE/SC–0095, Publication Date: June 2006

outside or bark is less permeable and flexible.

These differences among the cellulosic feedstock plant structures, e.g., density, rigidity, hardness, etc., suggest that different conversion processes, namely biochemical and thermochemical may be necessary to convert into ethanol as much of the available plant material as possible. For example, if wood chips, e.g., poplar trees, are to be treated biochemically, the chips must be reduced in size to 1-mm or less in order to increase the surface area for contact with acid, enzymes, etc. Breaking up a 5-in stem to such small pieces would consume a large amount of energy. On the other hand, processing corn stover into cellulosic ethanol has a maximum size of up to 1.5 inches (28 millimeters) in length because corn stover is so thin.[445] By comparison, the particle size requirement for a thermochemical process is around 10-mm to 100-mm in diameter.[446] Because of this, we believe feedstocks such as corn stover, wheat and rice straw, and switchgrass will likely be feedstocks for biochemical processes. Biochemical plants will likely be constructed in those areas of the country where these feedstocks are most abundant, e.g., the corn belt and upper Midwest. On the other hand, thermochemical plants will likely be constructed in those areas of the country where forest thinnings, forest fuel-removal operations, lumber production, and paper mills are most predominant, e.g., the South. Thermochemical or gasification units could be constructed near starch or biochemical cellulosic plants in order to take advantage of byproduct streams. We expect switchgrass (SG) will preferentially be fed to biochemical units since it is similar to straw, whereas short-rotation woody crops (SRWC) such as willows or poplars will preferentially be fed to thermochemical units.

Biochemically, it is much more difficult to convert cellulosic plant matter into ethanol than it is to convert the starch from corn grain into ethanol. Corn starch consists of long polysaccharide chains that are weakly attracted to each other, quite flexible, and tend to curl up to form tiny particle-like bundles. This loose, flexible structure permits water and water-borne hydrolyzing enzymes to easily penetrate the polymer during the process stage known as hydrolysis. Once hydrolyzed, the corn starch sugar residues are easily fermentable.

The hydrolysis of cellulosic biomass is much more challenging. Unlike starch, cellulosic plant matter is made up of three main constituents: Cellulose, hemicellulose, lignin, and minor amounts of various other organic and inorganic chemicals.

Cellulose, the major constituent, is a polymer made up of only β-linked glucose monosaccharides. This molecular arrangement allows intra-molecular hydrogen bonds to develop within each monomer and inter-molecular hydrogen bonds to develop between adjacent polymers to form tight, rigid, strong, mostly straight polymer bundles that are insoluble in water and resistant to chemical attack. The net result of the structural characteristics makes cellulose much more difficult to hydrolyze than is hemicellulose.

Hemicellulose contributes significantly to the total fermentable sugars of the lignocellulosic biomass. Unlike cellulose, hemicellulose is chemically heterogeneous and highly substituted. Compared to cellulose, this branching renders it amorphous and relatively easy to hydrolyze to its constituent sugars.[447]

Lignin, the third principle component, is a complex, cross-linked polymeric, high molecular weight substance derived principally from coniferyl alcohol by extensive condensation polymerization. While cellulose and hemicellulose contribute to the amount of fermentable sugars for ethanol production, lignin is not so readily digestable, but can be combusted to provide process energy in a biochemical plant or used as feedstock to a thermochemical process.[448]

Because of the complexities in digesting cellulosic biomass, the residence time is longer to digest the cellulose and perform the fermentation. Thus, the cellulosic plant capital costs are higher than those of corn (starch) ethanol plants. However, because corn is a food source with an intrinsic food value, corn ethanol's feedstock costs are almost two times higher per ton (more than two times higher in the case for cellulose from MSW) than the feedstocks of a cellulosic ethanol plant. It is conceivable that depending on the cellulosic plant technology which drives its capital and operating costs that cellulosic ethanol plants' lower feedstock costs could offset its higher capital costs resulting in lower production costs than corn-based ethanol.

The National Renewable Energy Laboratory has been evaluating the state of biochemical cellulosic plant technology over the past decade or so, and it has identified principal areas for improvement. In 1999, it released its first report on the likely design concept for an nth generation biochemical cellulosic ethanol plant which projected the state of technology in some future year after the improvements were adopted. In 2002, NREL released a follow-up report which delved deeper into biochemical plant design in areas that it had identified in the 1999 report as deserving for additional research. Again, the 2002 report estimated the ethanol production cost for an nth generation biochemical cellulosic ethanol plant. These reports not only helped to inform policy makers on the likely capability and cost for biochemically converting cellulose to ethanol, but it helped to inform biochemical technology researchers on the most likely technology improvements that could be incorporated into these plant designs.

To comply with the RFS 2 requirements, NREL assessed the likely state of biochemical cellulosic plant technology over the years that the RFS standard is being phased in. The specific years assessed by NREL were 2010, 2015 and 2022. The year 2010 technology essentially represents the status of today's biochemical cellulosic plants. The year 2015 technology captures the expected near-term improvements including the rapid improvements being made in enzyme technology. The year 2022 technology captures the cost of mature biochemical cellulosic plant technology. Table VIII.A.1–3 summarizes NREL's estimated and projected production costs for biochemical cellulosic ethanol plant technology in these three years

[445] A. Aden, M. Ruth, K. Ibsen, J. Jechura, K. Neeves, J. Sheehan, and B. Wallace, National Renewable Energy Laboratory (NREL); L. Montague, A. Slayton, and J. Lukas Harris Group, Seattle, Washington, *Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis for Corn Stover;* June 2002; NREL is a U.S. Department of Energy Laboratory operated by Midwest Research Institute • Battelle • Bechtel; Contract No. DE–AC36–99–GO10337.

[446] Lin Wei, Graduate Research Assistant, Lester O. Pordesimo, Assistant Professor, Willam D. Batchelor, Professor, Department of Agricultural and Biological Engineering, Mississippi State University, MS 39762, USA, *Ethanol Production from Wood: Comparison of Hydrolysis Fermentation and Gasification Biosynthesis,* Paper Number: 076036, Written for presentation at the 2007 ASABE Annual International Meeting. Minneapolis Convention Center, Minneapolis, MN, 17–20 June 2007.

[447] Hans P. Blaschek, Professor and Thaddeus C. Ezeji, Research Assistant, Department of Food Science and Human Nutrition, University of Illinois, Urbana-Champaign. *Science of Alternative Feedstocks.*

[448] Glossary of Biomass Terms, National Renewable Energy Laboratory, Golden, CO. *http://www.nrel.gov/biomass/glossary.html.*

reflecting our average feedstock costs and adjusting the capital costs to a 7 percent before tax rate of return.

TABLE VIII.A.1–3—BIOCHEMICAL CELLULOSIC ETHANOL PRODUCTION COSTS PROVIDED BY NREL

Year technology	2010		2015		2022	
Plant Size MMgal/yr	56		69		71	
Capital Cost $MM	232		220		199	
	$MM/yr	c/gal	$MM/yr	c/gal	$MM/yr	c/gal
Capital Cost 7% ROI before taxes	25	46	24	35	22	31
Fixed Costs	9	16	9	12	8	12
Feedstock Cost	55	99	55	79	55	77
Other raw matl. costs	17	30	4	5	16	16
Enzyme Cost	18	32	7	10	5	8
Enzyme nutrients	8	14	2	3	2	2
Electricity	−6	−10	−7	−9	−12	−16
Waste disposal	1	2	3	4	1	1
Total Costs	127	229	96	139	84	131

NREL's projected improvements in production costs over time are based on improved reaction biochemistry. Before discussing the expected improvements in the reaction biochemistry, we will discuss the reaction pathway for cellulosic biochemical.

There are two primary reaction steps in a biochemical cellulosic ethanol plant. The first is hydrolysis. Hydrolysis breaks the polysaccharides into their sugar residues. The pretreated slurry is fed to a hydrolysis reactor; there may be multiple reactors, depending on the desired production rate. Dilute sulfuric acid is used to hydrolyze, primarily, the hemicellulose polysaccharides, xylan, mannan, arabinan, and galactan, to produce the mixed sugars. Very little of the cellulose polysaccharide, glucan, is hydrolyzed.

The second is saccharification and co-fermentation. Using a cellulase enzyme cocktail, saccharification of the cellulose to glucose occurs first at an elevated temperature to take advantage of increased enzyme activity, which reduces the quantity of required enzyme as well as the reaction time. Following cellulose saccharification, both the glucose and xylose sugars are co-fermented. Although xylan, the hemicellulose polysaccharide, is more easily hydrolyzed than glucan (cellulose polysaccharides), the xylose sugar is more difficult to ferment than the glucose sugar. Different microbes as well as different residence times and process conditions are required for each. Therefore, it may be necessary to separate the glucose and xylose monomers before fermentation.

Because xylan can make up as much as 25% of plant matter it is imperative that most of be available for ethanol production; the economic viability of biochemically produced ethanol depends heavily it. Good progress has been toward that end during the past few years.[449]

Also during the past few years, researchers have been developing ways to combine saccharification and fermentation into a single step through the use of enzyme/microbe cocktails. DOE and the National Renewable Energy Laboratory (NREL) have also supported research into more efficient, less costly enzymes for SSF. With their support, a less expensive, more efficient enzyme cocktail for cellulosic biomass fermentation has been developed.[450] Others have also reported some success in co-fermenting glucose and xylose.[451]

As the biochemical enzymatic pathway is streamlined using more cost-effective enzymes, and as these enzymes can more comprehensively saccarify and ferment the cellulose, the conversion fraction of the cellulose to ethanol will increase and the conversion time will decrease. An important benefit for these efficiency improvements is that the number and size of reaction vessels decrease, leading to lower capital costs and lower fixed operating costs. It is also estimated that less nutrients would be needed to maintain the enzymes reactivity. Because the production volume of ethanol will increase relative to the quantity of feedstock, it lowers the operating costs per gallon of ethanol. Between these various effects, the per-gallon costs for producing cellulosic ethanol through the biochemical pathway are expected to decrease dramatically. It is through these expected improvements that NREL has estimated reduced production costs for biochemical cellulosic ethanol plants.

Thermochemical conversion is another reaction pathway which exists for converting cellulose to ethanol. Thermochemical technology is based on the heat and pressure-based gasification or pyrolysis of nearly any biomass feedstock, including those we've highlighted as likely biochemical feedstocks. The syngas is converted into mixed alcohols, hydrocarbon fuels, chemicals, and power. A thermochemical unit can also complement a biochemical processing plant to enhance the economics of an integrated biorefinery by converting lignin-rich, non-fermentable material left over from high-starch or cellulosic. NREL has not yet estimated the cost of thermochemically converting cellulose to ethanol, so we did not include a cost estimate using this potential conversion pathway in our analysis and based our cost analysis entirely on the biochemical route.[452] However, one

[449] *Purdue yeast makes ethanol from agricultural waste more effectively,* Purdue News, June 28, 2004 *http://www.purdue.edu/UNS/html4ever/2004/040628.Ho.ethanol.html.*

[450] *GENENCOR LAUNCHES FIRST EVER COMMERCIAL ENZYME PRODUCT FOR CELLULOSIC ETHANOL,* ROCHESTER, NY, World-Wire, October 22, 2007 Copyright© 2007. All rights reserved. World-Wire is a resource provided by Environment News Service. *http://world-wire.com/news/0710220001.html.*

[451] Ali Mohagheghi, Kent Evans, Yat-Chen Chou, and Min Zhang, Biotechnology Division for Fuels and Chemicals, National Renewable Energy Laboratory, Golden, CO 80401, *Co-fermentation of Glucose, Xylose, and Arabinose by Genomic DNA–Integrated Xylose/Arabinose Fermenting Strain of Zymomonas mobilis AX101,* Applied Biochemistry and Biotechnology Vols. 98–100, 2002, Copyright© 2002 by Humana Press Inc., All rights of any nature whatsoever reserved.

[452] NREL has authored a thermochemical report: Phillips, S Thermochemical Ethanol via Indirect Gasification and Mixed Alcohol Synthesis of Lignocellulosic Biomass; April, 2007, which does provide a cost estimate. However, this report only hypothesized how a thermochemical ethanol plant could achieve production costs at $1 per gallon, and

Continued

report estimated that the costs are similar for converting cellulose to ethanol either through either the biochemical or thermochemical routes. Thus, we believe that our cellulosic ethanol costs are representative of both technologies. In Section VIII.A.3 below, we discuss the costs for a thermochemical route for producing diesel fuel, often referred to as biomass-to-liquids (BTL) process.

c. Imported Sugarcane Ethanol

We based our imported ethanol fuel costs on cost estimates of sugarcane ethanol in Brazil. Generally, ethanol from sugarcane produced in developing countries with warm climates is much cheaper to produce than ethanol from grain or sugar beets. This is due to favorable growing conditions, relatively low cost feedstock and energy inputs, and other cost reductions gained from years of experience.

As discussed in Chapter 4 of the DRIA, our literature search of production costs for sugar cane ethanol in Brazil indicates that production costs tend to range from as low as $0.57 per gallon of ethanol to as high as $1.48 per gallon of ethanol. This large range for estimating production costs is partly due to the significant variations over time in exchange rates, costs of sugarcane and oil products, etc. For example, earlier estimates may underestimate current crude and natural gas costs which influence the cost of feedstock as well as energy costs at the plant. Another possible difference in production cost estimates is whether or not the estimates are referring to hydrous or anhydrous ethanol. Costs for anhydrous ethanol (for blending with gasoline) are typically several cents per gallon higher than hydrous ethanol (for use in dedicated ethanol vehicles in Brazil).[453] It is not entirely clear from the majority of studies whether reported costs are for hydrous or anhydrous ethanol. Yet another difference could be the slate of products the plant is producing, for example, future plants may be dedicated ethanol facilities while others involve the production of both sugar and ethanol in the same facility. Due to economies of scale, production costs are also typically smaller per gallon for larger facilities.

The study by OECD (2008) entitled ''Biofuels: Linking Support to Performance'', appears to provide the most recent and detailed set of assumptions and production costs. As such, our estimate of sugarcane production costs primarily relies on the assumptions made for the study, which are shown in Table VIII.A.1–4. The estimate assumes an ethanol-dedicated mill and is based off an internal rate of return of 12%, a debt/equity ratio of 50% with an 8% interest rate and a selling of surplus power at $57 per MWh.

TABLE VIII.A.1–4—COST OF PRODUCTION IN A STANDARD ETHANOL PROJECT IN BRAZIL

Sugarcane Productivity	71.5 t/ha.
Sugarcane Consumption	2 million tons/year.
Harvesting days	167.
Ethanol productivity	85 liters/ton (22.5 gal/ton).
Ethanol production	170 million liters/year (45 MGY).
Surplus power produced	40 kWh/ton sugarcane.
Investment cost in mill	USD 97 million.
Investment cost for sugarcane production	USD 36 million.
O & M (Operating & Maintenance) costs	$0.26/gal.
Sugarcane costs	$0.64/gal.
Capital costs	$0.49/gal.
Total production costs	$1.40/gal.

The estimate above is based on the costs of producing ethanol in Brazil on average, today. However, we are interested in how the costs of producing ethanol will change by the year 2022. Although various cost estimates exist, analysis of the cost trends over time shows that the cost of producing ethanol in Brazil has been steadily declining due to efficiency improvements in cane production and ethanol conversion processes. Between 1980 and 1998 (total span of 19 years) ethanol cost declined by approximately 30.8%.[454] This change in the cost of production over time in Brazil is known as the ethanol cost ''Learning Curve''.

The change in ethanol costs will depend on the likely productivity gains and technological innovations that can be made in the future. As the majority of learning may have already occurred, it is likely that the decline in sugarcane ethanol costs will be less drastic as the production process and cane practices have matured. This is in contrast to younger technologies such as those used to produce cellulosic biofuels which could likely have larger cost reductions over the same period of time. In fact, there are few perspectives for substantial efficiency gains with the sugarcane processing technology. Industrial efficiency gains are already at about 85% and are expected to increase to 90% in 2015.[455] Most of the productivity growth is expected to come from sugarcane production, where yields are expected to grow from the current 70 tons/ha, to 96 tons/ha in 2025.[456] Sugarcane quality is also expected to improve, with sucrose content growing from 14.5% to 17.3% in 2025.[457] All productivity gains together could allow the increase in the production of ethanol from 6,000 liters/ha (at 85 liters/ton sugarcane in 2005) to 10,400 liters/ha (at 109 liters/ton sugarcane) by 2025.[458] Although not reflected here, there could also be cost and efficiency improvements related to feedstock collection, storage, and distribution.

Assuming that ethanol productivity increases to 100 liters/ton by 2015 and 109 liters/ton by 2025, sugarcane costs are be expected to decrease to approximately $0.51/gal from $0.64/gal since less feedstock is needed to produce the same volume of ethanol

thus it could not be relied upon for any part of our real-world program cost analysis.

[453] International Energy Agency (IEA), ''Biofuels for Transport: An International Perspective,'' 2004.

[454] Goldemberg, J. as sited in Rothkopf, Garten, ''A Blueprint for Green Energy in the Americas,'' 2006.

[455] Unicamp ''A Expansão do Proalcool como Programa de Desenvolvimento Nacional''. Powerpoint presentation at *Ethanol Seminar* in BNDES, 2006. As sited in OECD, ''Biofuels: Linking Support to Performance,'' ITF Round Tables No. 138, March 2008.

[456] *Ibid.*

[457] *Ibid.*

[458] *Ibid.*

using the estimates from Table VIII.A.1–4, above. We assumed a linear decrease between data points for 2005, 2015, and 2025. Adding operating ($0.26/gal) and capital costs ($0.49/gal) from Table VIII.A.1–4, to a sugarcane cost of $0.51/gal, total production costs are $1.26/gal in 2022.

Brazil sugarcane producers are also expected to move from burned cane manual harvesting to mechanical harvesting. As a result, large amounts of straw are expected to be available. Costs of mechanical harvesting are lower compared to manually harvesting, therefore, we would expect costs for sugarcane to decline as greater sugarcane producers move to mechanical harvesting. However, it is important to note that diesel use increases with mechanical harvesting, and with diesel fuel prices expected to increase in the future, costs may be higher than expected. Therefore, we have not assumed any changes to harvesting costs due to the switchover from manual harvesting to mechanical harvesting.

As more straw is expected to be collected at future sugarcane ethanol facilities, there is greater potential for production of excess electricity. The production costs estimates in the OECD study assumes an excess of 40kWh per ton sugarcane, however, future sugarcane plants are expected to produce 135 kWh per ton sugarcane.[459] Assuming excess electricity is sold for $57 per MWh, the production of 95 kWh per ton would be equivalent to a credit of $0.22 per gallon ethanol produced. We did not include this potential additional credit from greater use of bagasse and straw in our estimates at this time. Our cost estimates do include, however, the excess electricity produced from bagasse that is currently used today (40 kWh/ton). We are asking for comment on whether such a credit should be included in our production cost estimates.

It is also important to note that ethanol production costs can increase if the costs of compliance with various sustainability criteria are taken into account. For instance, using organic or green cane production, adopting higher wages, etc. could increase production costs for sugarcane ethanol.[460] Such sustainability criteria could also be applicable to other feedstocks, for example, those used in corn- or soy-based biofuel production. If these measures are adopted in the future, production costs will be higher than we have projected.

In addition to production costs, there are also logistical and port costs. We used the report from AgraFNP to estimate such costs since it was the only resource that included both logistical and port costs. The total average logistical and port cost for sugarcane ethanol is $0.19/gal and $0.09/gal, respectively, as shown in Table VIII.A.1–5.

TABLE VIII.A.1–5—IMPORTED ETHANOL COST AT PORT IN BRAZIL (2006 $)

Region	Logistical costs U.S. ($/gal)	Port cost U.S. ($/gal)
NE Sao Paulo	0.146	0.094
W Sao Paulo	0.204	0.094
SE Sao Paulo	0.100	0.094
S Sao Paulo	0.170	0.094
N Parana	0.232	0.094
S Goias	0.328	0.094
E Mato Grosso do sul	0.322	0.094
Triangulo mineiro	0.201	0.094
NE Cost	0.026	0.058
Sao Francisco Valley	0.188	0.058
Average	0.192	0.087

Total fuel costs must also include the cost to ship ethanol from Brazil to the U.S. In 2006, this cost was estimated to be approximately $0.15 per gallon of ethanol.[461] Costs were estimated as the difference between the unit value cost of insurance and freight (CIF) and the unit value customs price. The average cost to ship ethanol from Caribbean countries (e.g., El Salvador, Jamaica, etc.) to the U.S. in 2006 was approximately $0.12 per gallon of ethanol. Although this may seem to be an advantage for Caribbean countries, it should be noted that there would be some additional cost for shipping ethanol from Brazil to the Caribbean country. Therefore, we assume all costs for shipping ethanol to be $0.15 per gallon regardless of the country importing ethanol to the U.S.

Total imported ethanol fuel costs (at U.S. ports) prior to tariff and tax for 2022 is shown in Table VIII.A.1–6, at $1.69/gallon. Direct Brazilian imports are also subject to an additional $0.54 per gallon tariff, whereas those imports arriving in the U.S. from Caribbean Basin Initiative (CBI) countries are exempt from the tariff. In addition, all imports are given an ad valorem tax of 2.5% for undenatured ethanol and a 1.9% tax for denatured ethanol. We assumed an ad valorem tax of 2.5% for all ethanol. Thus, including tariffs and ad valorem taxes, the average cost of imported ethanol is shown in Table VIII.A.1–7 in the ''Brazil Direct w/Tax & Tariff'' and ''CBI w/Tax'' columns for 2022.

[459] Macedo. I.C., ''Green house gases emissions in the production and use of ethanol from sugarcane in Brazil: The 2005/2006 Averages and a Prediction for 2020,'' *Biomass and Bioenergy,* 2008.

[460] Smeets E, Junginger M, Faaij A, Walter A, Dolzan P, Turkenburg W, ''The sustainability of Brazilian ethanol—An Assessment of the possibilities of certified production,'' Biomass and Bioenergy, 2008.

[461] Official Statistics of the U.S. Department of Commerce, USITC.

TABLE VIII.A.1–6—AVERAGE IMPORTED ETHANOL COSTS PRIOR TO TARIFF AND TAXES IN 2022

Sugarcane production cost ($/gal)	Operating cost ($/gal)	Capital cost ($/gal)	Logistical cost ($/gal)	Port cost ($/gal)	Transport cost from port to U.S. ($/gal)	Total cost ($/gal)
0.51	0.26	0.49	0.19	0.09	0.15	1.69

TABLE VIII.A.1–7—AVERAGE IMPORTED ETHANOL COSTS IN 2022

Brazil direct ($/gal)	Brazil direct w/tax & tariff ($/gal)	CBI ($/gal)	CBI w/tax ($/gal)
1.69	2.27	1.69	1.73

2. Biodiesel and Renewable Diesel Production Costs

Biodiesel and renewable diesel production costs are primarily a function of the feedstock cost, and to a much lesser extent, the capital and other operating costs of the facility.

a. Biodiesel

Biodiesel production costs for this rule were estimated using two versions of a biodiesel production facility model obtained from USDA, one using degummed soy oil as a feedstock and the other using yellow grease. The biodiesel from yellow grease model includes the acid pre-treatment steps required to utilize feedstocks with high free fatty acid content.

This production model simulates a 10 million gallon per year plant operating a continuous flow transesterification process. USDA used the SuperPro Designer chemical process simulation software to estimate heat and material flowrates and equipment sizing. Outputs from this software were then combined in a spreadsheet with equipment, energy, labor, and chemical costs to generate a final estimate of production cost. The model is described in a 2006 publication in Bioresource Technology, peer-reviewed scientific journal.[462] Table VIII.A.2–1 shows the production cost allocation for the soy oil-to-biodiesel facility as modeled in the 2022 policy case.

TABLE VIII.A.2–1—PRODUCTION COST ALLOCATION FOR SOY BIODIESEL DERIVED FROM THIS ANALYSIS

Cost category	Contribution to cost (percent)
Soy Oil	87
Other Materials [a]	5
Capital & Facility	4
Labor	3
Utilities	1

[a] Includes acids, bases, methanol, catalyst.

[462] Haas, M.J., A process model to estimate biodiesel production costs, Bioresource Technology 97 (2006) 671–678.

Soy oil costs were generated by the FASOM agricultural model (described in more detail in Section IX.A). Historically, the majority of biodiesel production in the U.S. has used soy oil, a relatively high-value feedstock, but a growing fraction of biodiesel is being made from yellow grease, the name given to reclaimed or highly-processed oil (including corn oil extracted from distillers' grains) that is not suitable for use in food products. This material typically sells for about 70% of the value of virgin soy oil. Conversion of yellow grease into biodiesel requires an additional acid pretreatment step, and therefore the processing costs are higher than for virgin soy oil (about $0.40/gal at equal feedstock costs). Table VIII.A.2–2 shows the feedstock and biodiesel costs used in our cost analysis.

TABLE VIII.A.2–2—BIODIESEL FEEDSTOCK AND PRODUCTION COSTS USED IN THIS ANALYSIS (2006$)

	Soy oil	Yellow grease [a]
Reference Case		
Feedstock $/lb	$0.23	$0.16
Biodiesel $/gal	$2.11	$1.99
Policy Case		
Feedstock $/lb	$0.32	$0.22
Biodiesel $/gal	$2.75	$2.47

[a] Includes corn oil extracted from thin stillage/DGS, rendered fats, recycled greases, etc.

A co-product of transesterification is crude glycerin. With the upswing in worldwide biodiesel production in recent years, its market price is relatively low: In our modeling we assume its value to be $0.03/lb. As a result, the sale of this material as a co-product only reduces biodiesel production cost by about $0.02/gal.

b. Renewable Diesel

Renewable diesel is produced in one of three general configurations: (1) A new standalone unit located within a refinery, (2) co-processing in an existing refinery diesel hydrotreater, or (3) a standalone unit at a rendering plant or another location outside of a refinery. We expect that the largest fraction of the capacity for refinery installation will be produced using the co-processing method, as the production costs are lower than those for a new standalone unit in a refinery. Thus, we speculate that about 50% of renewable diesel being produced by the refinery co-processing route, 17% from a new stand alone unit at a refinery and 33% at rendering plants or as a new site installation. Recent business partnership and construction announcements related to renewable diesel production (such as involving ConocoPhillips facilities in Texas, and

Tyson-Syntroleum facilities in Louisiana) generally support such a split.

We derived our production cost estimates from documents made available publicly by UOP, Inc., to make renewable diesel in a grass roots standalone production process inside a refinery.[463] The process has a pre-treating unit that removes alkali and acidic producing compounds from feed streams, which removes the catalyst poisons. We also used the UOP engineering estimate to derive costs for co-processing renewable diesel in an existing refinery's diesel hydrotreater. For this, we assumed that refiners will: (1) revamp their existing diesel hydrotreater to add capacity and (2) add a pre-treater to remove feedstock contaminants. Lastly, we derived costs for a standalone unit at a location outside a refinery at a rendering plant other facility, using a capital cost estimate from Syntroleum Corp.[464]

The extent of the depolymerization and hydrotreating reactions depend on the process conditions, as some of the carbon backbone of the oils can be cracked to naphtha and lighter products with higher severity. For our analysis, we assume no such cracking and predict yields resulting in ninety-nine percent diesel fuel with the balance as propane (which could also be considered renewable fuel) and water. We assume that all of the renewable diesel production will take place in PADD 2, as feedstock shipping costs are reduced since most of the sources for feedstock supply are located primarily in the Midwest. Average processing cost per gallon (in addition to the feedstock) is 41 cents for making renewable diesel from yellow grease/animal fats, based on our cost methodology.

As with biodiesel, renewable diesel cost estimates were based on soy oil feedstock prices taken from the FASOM modeling work, given in Section IX.A. Our cost estimates for renewable diesel were focused on use of yellow grease as a feedstock, given the project announcements mentioned above, as well as the relative insensitivity of the hydrotreating process to fatty acids and other contaminates relative to the transesterification process. Oil from corn fractionation, yellow grease, and animal fat prices were assumed to be 70% the price of soy oil (consistent with historical market trends). For our 2022 policy case, with a yellow grease price of $0.23/lb, the production cost is $2.47/gal for biodiesel and $2.10/gal for renewable diesel (2006$). Table VIII.A.2–3 shows the projected volume contribution to the biodiesel and renewable diesel total volume, their production costs, and the weighted average production cost used for biodiesel and renewable diesel in this proposal. These results assume feedstock prices are plant-gate and do not include any product transportation costs. Note also that the volumes here include co-processed renewable diesel which does not qualify as biomass-based diesel but which may be counted as advanced biofuel.

TABLE VIII.A.2–3—PROJECTED COSTS AND VOLUME CONTRIBUTION FOR BIODIESEL AND RENEWABLE DIESEL

[Policy case, 2006$ and million gallons]

Fuel	Cost	Volume
Biodiesel from virgin plant oil	2.75	660
Biodiesel from oil extraction at ethanol plants, yellow grease	2.47	150
Renewable diesel from fat, oil, yellow grease	2.10	375
Weighted average cost & total volume	2.51	1,185

Although the per-gallon cost for making renewable diesel from yellow grease is significantly less than using the biodiesel process, there are a number of reasons why we believe the latter will still be used to process some yellow grease (and most of the virgin oil feedstocks). The primary reason is that there is already sufficient biodiesel capacity existing or under construction to cover the projected volumes. Secondly, the per-gallon capital cost to build new hydroprocessing capacity for renewable diesel is expected to be significantly higher than for the biodiesel process. The low per-gallon renewable diesel cost given here is based on the majority of the production being done by co-processing at existing petroleum refineries.

3. BTL Diesel Production Costs

Biofuels-to-Liquids (BTL) processes, which are also thermochemical processes, convert biomass to liquid fuels via a syngas route. The primary product produced by this process is diesel fuel.

There are many steps involved in a BTL process which makes this a capital-intensive process. The first step, like all the cellulosic processes, requires that the feedstocks be processed to be dried and ground to a fine size. The second step is the syngas step, which thermochemically reacts the biomass to carbon monoxide and hydrogen. Since carbon monoxide production exceeds the stoichiometric ideal fraction of the mixture, a water shift reaction must be carried out to increase the relative balance of hydrogen. The syngas products must then be cleaned to facilitate the following Fischer-Tropsch reaction. The Fischer-Tropsch reaction reacts the syngas to a range of hydrocarbon compounds—a type of synthetic crude oil. This hydrocarbon mixture is then hydrocracked to maximize the production of high cetane diesel fuel, although some low octane naphtha is also produced. The many steps of the BTL process contribute to its high capital cost.

One estimate made by Iowa State University estimates the total cost for a cellulosic Fischer-Tropsch plant that produces 35 million gallons per year diesel fuel at $2.37 per gallon. This cost estimated the capital costs to be $341 million. These costs were estimated in the year 2002. We adjusted the operating and capital costs to a 2006 investment environment and to 2006 dollars based the costs on our average $71/dry ton feedstock costs which increases the total cost to $2.85 per gallon of diesel fuel.

Initially, the estimated cost of $2.85 per gallon seems high relative to the projected cost for a year 2015 biochemical cellulosic plant, which is $1.39 per gallon of ethanol in 2006 dollars. However, ethanol provides about half the energy content as Fischer-Tropsch diesel fuel. So if we double the biochemical cellulosic ethanol costs to $2.78 per diesel fuel-equivalent gallon,

[463] A New Development in Renewable Fuels: Green Diesel, AM–07–10 Annual Meeting NPRA, March 18–20, 2007.

[464] From Securities and Exchange Commission Form 8–K for Syntroleum Corp, June 25th 07.

the estimated costs are very consistent between the two. The cellulosic biofuel tax subsidy favors the biochemical ethanol plant, though, because it is a per-gallon subsidy regardless of the energy content, and it therefore offsets twice as much cost as the BTL plant producing diesel fuel. There is one more issue worth considering and that is the relative price of diesel fuel to that of E85. Recently diesel fuel has been priced much higher than gasoline, and if this trend continues to hold, it would provide a better market for selling the BTL diesel fuel than for selling biochemical ethanol into the E85 market, which we believe will be a challenging pricing market for refiners.

4. Catalytic Depolymerization Costs

A new technology was developed by Cello Energy which catalytically depolymerizes cellulose, and then repolymerizes it to produce synthetic hydrocarbon fuels such as gasoline, jet fuel and diesel fuel The company claims that they can produce diesel fuel for about $0.40 per gallon by processing hay, wood chips and used tires. Based on our projections of future cellulosic feedstock costs, their production costs for using only cellulosic feedstocks and assuming the cellulosic feedstock costs developed above would likely be about $1.00 per gallon. In late 2008 the company started up a 20 million gallon per year commercial demonstration plant as a first step towards commercializing their process. We discuss this technology and its costs in more detail in the DRIA.

B. Distribution Costs

Our analysis of the costs associated with distributing the volumes of renewable fuels that we project will be used under RFS2 focuses on: (1) The capital cost of making the necessary upgrades to the fuel distribution infrastructure system directly related to handling these fuels, and (2) the ongoing additional freight costs associated with shipping renewable fuels to the point where they are blended with petroleum-based fuels.[465] The following sections outline our estimates of the distribution costs for the additional volumes of ethanol, FAME biodiesel, and renewable diesel fuel that would be used in response to the RFS2 standards.[466]

[465] The anticipated ways that the renewable fuels projected to be used in response to the EISA will be distributed is discussed in Section V.C. of today's preamble.

[466] Please refer to Section 4.2 of the DRIA for additional discussion of how these estimates were derived.

A discussion of the capability of the transportation system to accommodate the volumes of renewable fuels projected to be used under RFS2 is contained in Section V.C. of today's preamble. There will be ancillary costs associated with upgrading the basic rail, marine, and road transportation nets to handle the increase in freight volume due to the RFS2. We have not sought to quantify these ancillary costs because (1) the growth in freight traffic that is attributable to RFS2 represents a minimal fraction of the total anticipated increase in freight tonnage (approximately 2% by 2022, see Section V.C.4.), and (2) we do not believe there is an adequate way to estimate such non-direct costs. We will continue to evaluate issues associated with the expansion of the basic transportation net to accommodate the volumes of renewable fuels projected under RFS2 and will update our analysis for the final rule based on our findings.

1. Ethanol Distribution Costs

a. Capital Costs To Upgrade the Distribution System for Increased Ethanol Volume

Table VIII.B.1–1 contains our estimates of the infrastructure changes and associated capital costs to support the use of the additional 21 BGY of ethanol that we project will be used under RFS2 by 2022 relative to the AEO 2007 forecast of 13 BGY.[467] The total estimated capital costs are estimated at $12.1 billion which when amortized equates to approximately 6.9 cents per gallon of this additional ethanol volume.[468]

TABLE VIII.B.1–1—ESTIMATED ETHANOL DISTRIBUTION INFRASTRUCTURE CAPITAL COSTS [A]

	Million $
Fixed Facilities:	
Marine Import Facilities	49
Ethanol Receipt Rail Hub Terminals:	
Rail Car Handling & Misc. Equipment	1,264
Ethanol Storage Tanks	354
Petroleum Terminals:	
Rail Receipt Facilities	2,482
Ethanol Storage Tanks	1,611
Ethanol Blending & Misc. Equipment	545
Retail	2,957
Mobile Facilities:	
Rail Cars	2,938
Barges	183
Tank Trucks	223
Total Capital Costs	12,066

[a] Relative to a 13.18 BGY 2022 reference case.

[467] *See* Section V.C. of today's preamble for discussion of the upgrades we project will be needed to the distribution system to handle the increase in ethanol volumes under EISA.

[468] These capital costs will be incurred incrementally through 2022 as ethanol volumes increase. Capital costs for tank trucks were amortized over 10 years with a 7% cost of capital. Other capital costs were amortized over 15 years with a 7% return on capital.

We request comment on our basis for these estimates as detailed in chapter 4.2 of the DRIA. Comment is specifically requested on the extent to which ethanol rail receipt would be accommodated within petroleum terminals rather than being cited at rail hub terminals (to be further shipped by tank truck to petroleum terminals). Our current analysis estimated that half of the new ethanol rail receipt capability needed to support the use of the projected ethanol volumes under the EISA would be installed at petroleum terminals, and half would be installed at rail terminals. A recently completed study by ORNL estimated that all new ethanol rail receipt capability would be installed at existing rail terminals given the limited ability to install such capability at petroleum terminals.[469]

b. Ethanol Freight Costs

We estimate that ethanol freight costs would be 11.3 cents per gallon on a national average basis. Ethanol freight costs are based on those we derived for the Renewable Fuel Standard final rule updated to reflect the projected ethanol use patterns and effect on distribution patterns of increased imports and more dispersed domestic ethanol production locations.[470] Specifically, we estimated freight costs by assessing the location of production and import volumes, where ethanol would be used, and the modes and distances for transportation between production and use.[471] We intend to update our estimate of ethanol freight costs for the final rule based on a recently completed analysis conducted for EPA by Oak Ridge National Laboratory (ORNL). The ORNL

[469] "Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints", prepared for EPA by Oak Ridge National Laboratory, March 2009.

[470] Please refer to Section 4.2 of the DRIA for additional discussion of ethanol freight costs.

[471] Our projections regarding the location of ethanol production/import volumes and where ethanol would be used is discussed in Sections V.B. and V.D. of today's preamble respectively.

analysis contains more detailed projections of which transportation modes and combination of modes (e.g., unit train to barge) are best suited for delivery of ethanol to specific markets considering ethanol source and end use locations, the current configuration and projected evolution of the distribution system, and cost considerations for the different transportation modes.

2. Biodiesel and Renewable Diesel Distribution Costs

a. Capital Costs To Upgrade the Distribution System for Increased FAME Biodiesel Volume

Table VIII.B.2–1 contains our estimates of the infrastructure changes and associated capital costs to support the use of the additional 430 MGY of FAME biodiesel that we project will be used under RFS2 by 2022.[472] The total capital costs are estimated at $381 million which equates to approximately 9.8 cents per gallon of additional biodiesel volume.[473]

TABLE VIII.B.2–1—ESTIMATED FAME BIODIESEL DISTRIBUTION INFRASTRUCTURE CAPITAL COSTS [a]

	Million $
Fixed Facilities:	
Petroleum Terminals:	
Storage Tanks	129
Biodiesel Blending & Misc. Equipment	192
Mobile Facilities:	
Rail Cars	35
Barges	17
Tank Trucks	8
Total Capital Costs	381

[a] Relative to a 380 MGY 2022 reference case.

b. Biodiesel Freight Costs

We estimate that biodiesel freight costs would be 9.3 cents per gallons on a national average basis. Priority regional demand for biodiesel was estimated by reviewing State biodiesel mandates/incentives and assuming a demand for 2% biodiesel in most heating oil used in the Northeast by 2022. This priority regional demand was assumed to be filled first from local plants that could ship economically by tank truck. The remaining fraction of priority regional demand was assumed to be satisfied from more distant plants via shipment by manifest rail car. Overall shipping distances were minimized in selecting which plants would satisfy the demand for a given area. The amount of biodiesel that we project would be consumed which would not be directed to priority demand was assumed to be used within trucking distance of the production plant to the extent possible while maintaining biodiesel blend concentrations below 5%. The remaining volume needed to match our estimated production volume was assumed to be shipped via manifest rail car to the nearest areas where diesel fuel use was not already saturated with biodiesel to the 5% level.

c. Renewable Diesel Distribution System Capital and Freight Costs

We project that there would be no additional costs associated with distributing the 250 MGY of renewable diesel fuel that we estimate will be produced at refineries by 2022.[474] This renewable diesel fuel will be blended into finished diesel fuel at the refinery and be distributed to petroleum terminals in the same way 100% petroleum-based distillate fuel is distributed. This is based on our belief that renewable diesel will be confirmed to be sufficiently similar to petroleum-based diesel with respect to distribution system compatibility.

We project that 125 MGY of renewable diesel will be produced at stand-alone facilities that are not connected to a refinery or petroleum terminal. We estimate that such renewable diesel will be trucked to nearby petroleum terminals at a cost of 5 cents per gallon. We estimate that 8 additional tank trucks would be needed to carry this renewable diesel to terminals at a total cost of approximately $1.3 million dollars. Amortized over 10 years with a 7% cost of capital, the total capital costs equate to approximately 0.2 cents per gallon of renewable diesel fuel produced at stand-alone facilities. We estimate that no further capital costs would need to be incurred to handle renewable diesel fuel. This is based on the assumption that renewable diesel delivered to terminals from stand-alone production facilities can be mixed directly into storage tanks that contain petroleum-based diesel fuel or can be stored separately in existing storage tanks for later blending with petroleum-based diesel fuel. We further estimate the terminals that receive renewable diesel will not need to install additional facilities to allow the receipt by tank truck.

C. Reduced Refining Industry Costs

As renewable and alternative fuel use increases, the volume of petroleum-based products, such as gasoline and diesel fuel, would decrease. This reduction in finished refinery petroleum products is associated with reduced refinery industry costs. The reduced costs would essentially be the volume of fuel displaced multiplied by the cost for producing the fuel. There is also a reduction in capital costs which is important because by not investing in new refinery capital, more resources are freed up to build plants that produce renewable and alternative fuels.

Although we conducted refinery modeling for estimating the cost of blending ethanol, we did not rely on the refinery model results for estimating the volume of displaced petroleum. Instead we conducted an energy balance around the increased use of renewable fuels, estimating the energy-equivalent volume of gasoline or diesel fuel displaced. This allowed us to more easily apply our best estimates for how much of the petroleum would displace imports of finished products versus crude oil for our energy security analysis which is discussed in Section IX.B of this preamble.

As part of this analysis we accounted for the change in petroleum demanded by upstream processes related to additional production of the renewable fuels as well as reduced production of petroleum fuels. For example, growing corn used for ethanol production requires the use of diesel fuel in tractors, which reduces the volume of petroleum displaced by the ethanol. Similarly, the refining of crude oil uses by-product hydrocarbons for heating within the refinery, therefore the overall effect of reduced gasoline and diesel fuel consumption is actually greater because of the additional upstream effect. We used the lifecycle petroleum demand estimates provided for in GREET model to account for the upstream consumption of petroleum for each of the renewable and alternative fuels, as well as for gasoline and diesel fuel. Although there may be some renewable fuel used for upstream energy, we assumed that this entire volume is petroleum because the volume of renewable and alternative fuels is fixed as described in Section V above.

For this proposed rule, we assumed that a portion of the gasoline displaced

[472] We project that by 2022 380 MGY of FAME biodiesel would be used absent the requirements under EISA and that a total of 810 MGY of FAME biodiesel would be used under the EISA.

[473] These capital costs will be incurred incrementally through 2022 as FAME biodiesel volumes increase. Capital costs for tank trucks were amortized over 10 years with a 7% cost of capital. Other capital costs were amortized over 15 years with a 7% return on capital.

[474] This includes co-processed renewable diesel fuel as well as renewable diesel fuel produced in separate processing units located at refineries.

by ethanol is imported, while the other portion is produced from domestic refineries. The assumption we made is that one half of the ethanol market in the Northeast, which comprises about half of the nation's gasoline demand, would displace imported gasoline or gasoline blend stocks. Therefore, to derive the portion of the new renewable fuels which would offset imports (and not impact domestic refinery production), we multiplied the total volume of petroleum fuel displaced by 50% to represent that portion of the ethanol which would be used in the Northeast, and 50% again to only account for that which would offset imports. The rest of the ethanol, including half of the ethanol presumed to be used in the Northeast, is presumed to offset domestic gasoline production. In the case of biodiesel and renewable diesel, all of it is presumed to offset domestic diesel fuel production. For ethanol, biodiesel and renewable diesel, the amount of petroleum fuel displaced is estimated based on the relative energy contents of the renewable fuels to the fuels which they are displacing. The savings due to lower imported gasoline and diesel fuel is accounted for in the energy security analysis contained in Section IX.B.

For estimating the U.S. refinery industry cost reductions, we multiplied the estimated volume of domestic gasoline and diesel fuel displaced by the wholesale price for each of these fuels, which are $157 per gallon for gasoline, and $161 per gallon for diesel fuel at $53/bbl crude oil, and $267 per gallon for gasoline, and $335 per gallon for diesel fuel at $92/bbl crude oil. For the volume of petroleum displaced upstream, we valued it using the wholesale diesel fuel price. Table VIII.C.1–1 shows the net volumetric impact on the petroleum portion of gasoline and diesel fuel demand, as well as the reduced refining industry costs for 2022.

TABLE VIII.C.1–1—REDUCED U.S. REFINERY INDUSTRY COSTS FOR THE RFS2 PROGRAM IN 2022

		Total volume displaced (billion gallons)	Cost savings at $53/bbl crude oil price (billion dollars)	Cost savings at $92/bbl crude oil price (billion dollars)
Upstream	Petroleum	0.8	−$1.3	−$2.7
End Use	Gasoline	10.4	16.3	27.7
	Diesel Fuel	0.6	0.9	1.9
	Total	....	15.9	26.9

D. Total Estimated Cost Impacts

The previous sections of this chapter presented estimates of the cost of producing and distributing corn-based and cellulosic-based ethanol, imported ethanol, biodiesel, and renewable diesel. In this section, we briefly summarize the methodology used and the results of our analysis to estimate the cost and other implications for increased use of renewable fuels to displace gasoline and diesel fuel. An important aspect of this analysis is refinery modeling which primarily was used to estimate the costs of blending ethanol into gasoline, as well as the overall refinery industry impacts of the proposed fuel program. The refinery modeling was conducted by Jacobs Consultancy under subcontract to Southwest Research Institute. A detailed discussion of how the renewable fuel volumes affect refinery gasoline production volumes and cost is contained in Chapter 4 of the DRIA.

1. Refinery Modeling Methodology

The refinery modeling was conducted in three distinct steps. The first step involved the establishment of a 2004 base case which calibrated the refinery model against 2004 volumes, gasoline quality, and refinery capital in place. The EPA and ASTM fuel quality constraints in effect by 2004 are imposed on the products.

For the second step, we established a 2022 future year reference case which represents a business-as-usual case as estimated by the 2007Annual Energy Outlook (AEO). The refinery model assumed that the price of crude oil would average about $51 per barrel, though the results were later adjusted to reflect $53 and $92 per barrel crude oil prices. We also modeled the implementation of several new environmental programs that will have required changes in fuel quality by 2022, including the 30 part per million (ppm) average gasoline sulfur standard, the 15 ppm cap standards on highway and nonroad diesel fuel, the Mobile Source Air Toxics (MSAT) 0.62 volume percent benzene standard. We modeled the implementation of EPAct of 2005, which by rescinding the reformulated gasoline oxygenate standard, resulted in the discontinued use of MTBE, and a large increase in the amount of ethanol blended into reformulated gasoline. We also modeled the EISA Energy Bill corporate average fuel economy (café) standards in the reference case because it will be phasing-in, and affect the phase-in of the RFS2. We modeled 13.2 billion gallons of ethanol in the gasoline pool and 0.4 billion gallons of biodiesel in the diesel pool for 2022, which is the ''business-as-usual'' volume as projected by AEO 2007.

The third step, or the control case, involved the modeling of the 34 billion gallons of ethanol and 1 billion gallons of biodiesel and renewable diesel in 2022 to comply with EISA when the proposed renewable fuels program is fully phased-in. All the other environmental and ASTM fuel quality constraints are assumed to apply to the control case as well to solely model the impact of the RFS2 standards.

The price of ethanol and E85 used in the refinery modeling is a critical determinant of the overall economics of using ethanol. Ethanol was priced initially based on the historical average price spread between regular grade conventional gasoline and ethanol, but then adjusted post-modeling to reflect the projected production cost for both corn and cellulosic-based ethanol. The refinery modeling assumed that all ethanol added to gasoline for E10 is match-blended for octane by refiners in the reference and control cases, although splash blending of ethanol was assumed to be appropriate for the conventional gasoline for the base case based on EPA gasoline data. For the control case, E85 was assumed to be priced much lower than gasoline to reflect its lower energy content, longer refueling time and lower availability (*see* Chapter 4 of the DRIA for a detailed discussion for how we projected E85 prices). E85 is assumed to be blended with gasoline blendstock designed for blending with E10, and a small amount of butane to bring the RVP of E85 up to that of gasoline. Thus, unlike current practices today where E85 is blended at 85% in the summer and E70 in the winter, we assumed that E85 is blended at 85% year-round. E85 use in any one market is limited to levels which we estimated would reflect the ability of FFV vehicles in the area to consume the E85 volume.

The refinery model was provided some flexibility and also was constrained with respect to the applicable gasoline volatility standards for blending up E10. The refinery model allowed conventional gasoline and most low RVP control programs to increase by 1.0 pounds per square inch (psi) in Reid Vapor Pressure (RVP) waiver during the summer. However, wintertime conventional gasoline was assumed to comply with the wintertime ASTM RVP and Volume/Liquid (V/L) standards.

The costs for producing, distributing and using biodiesel and renewable diesel are accounted for outside the refinery modeling. Their production and distribution costs are estimated first, compared to the costs of producing diesel fuel, and then are added to the costs estimated by the refinery cost model for blending the ethanol.

The costs were adjusted to reflect the crude oil prices estimated by EIA in its Annual Energy Outlook (AEO). The AEO 2008 reference case projects that crude oil will be $53 per barrel in 2022, so we adjusted our costs slightly to reflect that slightly higher crude oil price. We also evaluated a higher crude oil price case. The high crude oil case price modeled for the AEO projects that crude oil will be $92 per barrel in 2022, so we adjusted our cost model to also estimate the program costs based on this higher crude oil cost. We estimated the program costs based on these different crude oil prices by adjusting the gasoline and diesel fuel prices to reflect the cost of crude oil. The crude oil costs also have a secondary impact on the production costs of various renewable and alternative fuels (e.g., petroleum used to grow corn which also has been reflected in our cost analysis).

2. Overall Impact on Fuel Cost

Based on the refinery modeling conducted for today's proposed rule, we calculated the costs for consuming the additional 22 billion gallons of renewable fuels in 2022 relative to the reference case. The costs are reported separately for blending ethanol into gasoline as E10 and E85, and for blending biodiesel and renewable diesel with diesel fuel. The costs are expressed two different ways. First, we express the full "engineering" cost of the program without the ethanol consumption tax subsidies in which the costs are based on the total accumulated costs of each of the fuels changes, at both reference case and high crude oil prices. Second, we express the costs subtracting the ethanol and biodiesel and renewable diesel consumption tax subsidies since some or perhaps most of the cost of the tax subsidy may not be reflected in the price consumers pay at retail. In all cases, the capital costs are amortized at seven percent return on investment (ROI) before taxes, and based on 2006 dollars.

a. Costs Without Federal Tax Subsidies

Table VIII.D.2–1 summarizes the costs without ethanol tax subsidies for each of the two control cases, including the cost for each aspect of the fuels changes, and the aggregated total and the per-gallon costs for all the fuel changes.[475] This estimate of costs reflects the changes in gasoline that are occurring with the expanded use of renewable and alternative fuels. These costs include the labor, utility and other operating costs, fixed costs and the capital costs for all the fuel changes expected. The per-gallon costs are derived by dividing the total costs over all U.S. gasoline and diesel fuel projected to be consumed in 2022. Note that these costs are incremental only to the reference case volumes of renewable fuels (costing out about 20 billion gallons of new renewable fuels) and does not reflect the costs of the renewable fuel volumes in the reference case.

TABLE VIII.D.2–1—ESTIMATED COSTS OF THE RFS2 PROGRAM IN 2022

[2006 dollars, 7% ROI before taxes]

		$53 per barrel of crude oil incremental to reference case	$92 per barrel of crude oil incremental to reference case
Gasoline Impacts	$billion/yr	17.0	4.1
	c/gal	10.91	2.65
Diesel Fuel Impacts	$billion/yr	0.78	−0.05
	c/gal	1.20	−0.07
Total Impact	$billion/yr	17.8	4.1

Our analysis shows, as expected, that the RFS2 program is more cost effective at the higher assumed price of crude oil. At our assumed crude oil price of $53 per barrel, the gasoline and diesel fuel costs are projected to increase by $17.0 billion and $0.78 billion, respectively, or $17.8 billion in total. Expressed as per-gallon costs, these fuel changes would increase the cost of producing gasoline and diesel fuel by 10.91 and 1.20 cents per gallon, respectively. At the assumed crude oil price of $92 per barrel, the gasoline costs are projected to increase by $4.1 billion and the diesel fuel costs are projected to decrease by $0.05 billion, or increase by $4.1 billion in total. Expressed as per-gallon costs, these fuel changes would increase gasoline costs by 2.65 and decrease diesel fuel costs by 0.07 cents per gallon at the higher crude oil price. Our analysis shows that at the higher crude oil price, ethanol, biodiesel and renewable diesel fuel use would be much less costly to use.

The increased use of renewable and alternative fuels would require capital investments in corn and cellulosic ethanol plants, and renewable diesel fuel plants. In addition to producing the fuels, storage and distribution facilities along the whole distribution chain, including at retail, will have to be constructed for these new fuels. Conversely, as these renewable and

[475] EPA typically assesses social benefits and costs of a rulemaking. However, this analysis is more limited in its scope by examining the average cost of production of ethanol and gasoline without accounting for the effects of farm subsidies that tend to distort the market price of agricultural commodities.

alternative fuels are being produced, they supplant gasoline and diesel fuel demand which results in less new investments in refineries compared to business as usual. In Table VIII.D.2–2, we list the total incremental capital investments that we project would be made for this proposed RFS2 rulemaking incremental to the AEO 2007 reference case.

TABLE VIII.D.2–2—TOTAL PROJECTED U.S. CAPITAL INVESTMENTS FOR THE RFS2 PROGRAM

[billion dollars]

Plant Type	Capital Costs
Corn Ethanol	4.0
Cellulosic Ethanol	50.1
Ethanol Distribution	12.4
Bio/Renew Diesel Fuel Production and Distribution	0.25
Refining	−7.9
Total	58.9

Table VIII.D.2–2 shows that the total U.S. incremental capital investments attributed to this program for 2022 are $58.9 billion. One contributing reason why the capital investments made for renewable fuels technologies is so much more than the decrease in refining industry capital investments is that a large part of the decrease in petroleum gasoline supply was from reduced imports. In addition, renewable fuels technologies are more capital intensive per gallon of fuel produced than incremental increases in gasoline and diesel fuel production at refineries.

b. Gasoline and Diesel Costs Reflecting the Tax Subsidies

Table VIII.D.2–3 below expresses the total and per-gallon gasoline costs for the two control scenarios showing the effect of the Federal tax subsidies. The Federal tax subsidy is 45 cents per gallon for each gallon of new corn ethanol blended into gasoline and $1.01 per gallon for each gallon of cellulosic ethanol. Imported ethanol also receives the 45 cents per gallon Federal tax subsidy, although the portion of imported ethanol which exceeds the volume of imported ethanol exempted through the Caribbean Basin Initiative (CBI) would have to pay a 51 cents per gallon tariff. We estimate that in 2022 imported ethanol would receive a net 23 cents per gallon subsidy after we account for both the subsidy and projected volume of imported ethanol subjected to the tariff. While there are also state ethanol tax subsidies we did not consider those subsidies. A $1 per gallon subsidy currently applies to biodiesel produced from virgin plant oils (i.e., soy) and a 50 cent per gallon subsidy applies to biodiesel and renewable diesel fuel produced from waste fats and oils; we assume that these subsidies continue.[476] The subsidies, if passed along to the consumer, reduce the apparent cost of the program to the consumer at retail since part of the program cost is being paid through taxes. The cost reduction attributed to the subsidies is estimated by multiplying the value of the subsidies times the volume of new corn and cellulosic ethanol used in transportation fuels.

TABLE VIII.D.2–3—ESTIMATED COSTS OF THE RFS2 PROGRAM IN 2022

[Reflecting Tax Subsidies, 2006 dollars, 7% ROI before taxes]

		$53 per barrel of crude oil incremental to reference case	$93 per barrel of crude oil incremental to reference case
Gasoline Impacts	$billion/yr	−0.74	−13.6
	c/gal	−0.48	−8.74
Diesel Fuel Impacts	$billion/yr	0.25	−0.57
	c/gal	0.39	−0.88
Total Impact	$billion/yr	−0.49	−14.2

Our analysis shows, as expected, that the overall costs of the RFS2 program appears to be lower when considering the ethanol consumption subsidies. At the assumed crude oil price of $53 per barrel, the gasoline and diesel fuel costs are projected to decrease by $0.74 billion and increase $0.25 billion, respectively, or $−0.49 billion in total. Expressed as per-gallon costs, these fuel changes would decrease gasoline costs by −0.48 cents per gallon and increase diesel fuel costs by 0.39 cents per gallon. At the assumed crude oil price of $92 per barrel, the gasoline and diesel fuel costs are projected to decrease by $13.6 billion and $0.57 billion, respectively, or $14.2 billion in total. Expressed as per-gallon costs, these fuel changes would decrease gasoline and diesel fuel by 8.74 and 0.88 cents per gallon, respectively. Reducing the cost by the tax subsidies, which more closely represents the prices paid by consumers at the pump, our analysis shows that at lower crude oil prices that the cost of the program would be very small. However, at the higher oil prices and including the subsidies, the program's costs are very negative.

IX. Economic Impacts and Benefits of the Proposal

A. Agricultural Impacts

EPA used two principal tools to model the potential domestic and international impacts of the RFS2 on the U.S. and global agricultural sectors. The Forest and Agricultural Sector Optimization Model (FASOM), developed by Professor Bruce McCarl of Texas A&M University and others, provides detailed information on domestic agricultural and greenhouse gas impacts of renewable fuels. The Food and Agricultural Policy Research Institute (FAPRI) at Iowa State University and the University of Missouri-Columbia maintains a number of econometric models that are capable of providing detailed information on impacts on international agricultural markets from the wider use of renewable fuels in the U.S.

FASOM is a long-term economic model of the U.S. agriculture sector that attempts to maximize total revenues for producers while meeting the demands of consumers. FASOM can be utilized to estimate which crops, livestock, and processed agricultural products would be produced in the U.S. given RFS2 biofuel requirements. In each model simulation, crops compete for price sensitive inputs such as land and labor at the regional level and the cost of

[476] The recent economic bailout law increased the subsidy provided to renewable diesel fuel to $1 per gallon, but we were not able incorporate this change in time for this proposed rulemaking.

these and other inputs are used to determine the price and level of production of primary commodities (e.g., field crops, livestock, and biofuel products). FASOM also estimates prices using costs associated with the processing of primary commodities into secondary products (e.g., converting livestock to meat and dairy, crushing soybeans to soybean meal and oil, etc.). FASOM does not capture short-term fluctuations (i.e., month-to-month, annual) in prices and production, however, as it is designed to identify long-term trends (i.e., five to ten years). The domestic results provided throughout this analysis incorporate the agricultural sector component of the FASOM model.

The FASOM model also contains a forestry component. Running both the forestry and agriculture components of the model would show the interaction between these two sectors. However, the analysis for this proposal only shows the results from the agriculture component with no interaction from the forestry sector, as the forestry component of the model is in the process of being updated. We plan to utilize a complete version of the model for our analysis in the final rule, where agricultural land use impacts also affect forestry land use, and cellulosic ethanol produced from the forestry sector will affect cellulosic ethanol production in the agriculture sector.

The FAPRI models are econometric models covering many agricultural commodities. These models capture the biological, technical, and economic relationships among key variables within a particular commodity and across commodities. They are based on historical data analysis, current academic research, and a reliance on accepted economic, agronomic, and biological relationships in agricultural production and markets. The international modeling system includes international grains, oilseeds, ethanol, sugar, and livestock models. In general, for each commodity sector, the economic relationship that supply equals demand is maintained by determining a market-clearing price for the commodity. In countries where domestic prices are not solved endogenously, these prices are modeled as a function of the world price using a price transmission equation. Since econometric models for each sector can be linked, changes in one commodity sector will impact other sectors. Elasticity values for supply and demand responses are based on econometric analysis and on consensus estimates. Additional information on the FASOM and FAPRI models is included in the Draft Regulatory Impact Analysis (DRIA Chapter 5).

For the agricultural sector analysis using the FASOM and FAPRI models of the RFS2 biofuel volumes, we assumed 15 billion gallons (Bgal) of corn ethanol would be produced for use as transportation fuel by 2022, an increase of 2.7 Bgal from the Reference Case. Also, we modeled 1.0 Bgal of biodiesel used as fuel in 2022, an increase of 0.6 Bgal from the Reference Case. In addition, we modeled an increase of 10 Bgal of cellulosic ethanol in 2022. In FASOM, this volume consists of 7.5 billion gallons of cellulosic ethanol coming from corn residue in 2022, 1.3 billion gallons from switchgrass and 1.4 billion gallons from sugarcane bagasse. Though these volumes differ slightly from those analyzed in Section V.B.2.c.iv, we will work to align the volumes for the final rulemaking.

Given the short timeframe for conducting this analysis, some of the projected sources of biofuels analyzed in the RFS2 proposal are not currently modeled in FASOM and FAPRI. For example, biodiesel from corn oil fractionation is not currently accounted for in FASOM. In addition, since FASOM is a domestic agricultural sector model, it can't be utilized to examine the impacts of the wider use of biofuel imports into the U.S. Also, neither of the two models used for this analysis—FASOM or FAPRI—include biofuels derived from domestic municipal solid waste or from the U.S. forestry sector. Thus, for the RFS2 agricultural sector analysis, these biofuel sources are analyzed outside of the agricultural sector models.

All the results presented in this section are relative to the AEO 2007 Reference Case renewable fuel volumes, which include 12.3 Bgal of grain-based ethanol, 0.4 Bgal of biodiesel, and 0.3 Bgal of cellulosic ethanol in 2022. The domestic figures are provided by FASOM, and all of the international numbers are provided by FAPRI. The detailed FASOM results, detailed FAPRI results, and additional sensitivity analyses are described in more detail in the DRIA. We seek comment on this analysis of the agricultural sector impacts resulting from the wider use of renewable fuels.

TABLE IX.A.1–1—BIOFUEL VOLUMES MODELED IN 2022

[Billions of Gallons]

Biofuel	Reference Case	Control Case	Change
Corn Ethanol	12.3	15.0	2.7
Corn Residue Cellulosic Ethanol	0	7.5	7.5
Sugarcane Bagasse Cellulosic Ethanol	0.3	1.4	1.1
Switchgrass Cellulosic Ethanol	0	1.3	1.3
Other Ethanol	0	0.2	0.2
Biodiesel	0.4	1.0	0.6

1. Commodity Price Changes

For the scenario modeled, FASOM predicts that in 2022 U.S. corn prices would increase by $0.15 per bushel (4.6%) above the Reference Case price of $3.19 per bushel. By 2022, U.S. soybean prices would increase by $0.29 per bushel (2.9%) above the Reference Case price of $9.97 per bushel. The price of sugarcane would increase $13.34/ton (41%) above the Reference Case price of $32.49 per ton by 2022. In 2022, beef prices would increase $0.93 per hundred pounds (1.4%), relative to the Reference Case price of $67.72 per hundred pounds. Additional price impacts are included in Section 5.1.1 of the DRIA.

TABLE IX.A.1–2—CHANGE IN U.S. COMMODITY PRICES FROM THE REFERENCE CASE

[2006$]

Commodity	Change	% Change
Corn	$0.15/bushel	4.6
Soybeans	$0.29/bushel	2.9
Sugarcane	$13.34/ton	41

TABLE IX.A.1–2—CHANGE IN U.S. COMMODITY PRICES FROM THE REFERENCE CASE—Continued

[2006$]

Commodity	Change	% Change
Fed Beef	$0.93/hundred pounds.	1.4

By 2022, the price of switchgrass is $30.18 per wet ton and the farm gate feedstock price of corn stover is $32.74/wet ton. These prices do not include the storage, handling, or delivery costs, which would result in a delivered price to the ethanol facility of at least twice the farm gate cost, depending on the region. We intend to update the costs assumptions (described in more detail in Section 4.1.1 of the DRIA) for the final rule and invite comment on these assumptions.

2. Impacts on U.S. Farm Income

The increase in renewable fuel production provides a significant increase in net farm income to the U.S. agricultural sector. FASOM predicts that net U.S. farm income would increase by $7.1 billion dollars in 2022 (10.6%), relative to the AEO 2007 Reference Case.

3. Commodity Use Changes

Changes in the consumption patterns of U.S. corn can be seen by the increasing percentage of corn used for ethanol. FASOM estimates the amount of domestically produced corn used for ethanol in 2022 would increase to 33%, relative to the 28% usage rate under the Reference Case. The rising price of corn and soybeans in the U.S. would also have a direct impact on how corn is used. Higher domestic corn prices would lead to lower U.S. exports as the world markets shift to other sources of these products or expand the use of substitute grains. FASOM estimates that U.S. corn exports would drop 263 million bushels (−9.9%) to 2.4 billion bushels by 2022. In value terms, U.S. exports of corn would fall by $487 million (−5.7%) to $8 billion in 2022.

U.S. exports of soybeans would also decrease under this proposal. FASOM estimates that U.S. exports of soybeans would decrease 96.6 million bushels (−9.3%) to 943 million bushels by 2022. In value terms, U.S. exports of soybeans would decrease by $691 million (−6.7%) to $9.7 billion in 2022.

TABLE IX.A.3–1—REDUCTIONS IN U.S. EXPORTS FROM THE REFERENCE CASE IN 2022

Exports	Change	% Change
Corn in Bushels	263 million	−9.9
Soybeans in Bushels	96.6 million	−9.3
Total Value of Exports	Change	% Change
Corn (2006$)	$487 million	−5.7
Soybeans (2006$)	$691 million	−6.7

Higher U.S. demand for corn for ethanol production would cause a decrease in the use of corn for U.S. livestock feed. Substitutes are available for corn as a feedstock, and this market is price sensitive. Several ethanol processing byproducts could also be used to replace a portion of the corn used as feed, depending on the type of animal. Distillers dried grains with solubles (DDGS) are a byproduct of dry milling ethanol production, and gluten meal and gluten feed are byproducts of wet milling ethanol production. By 2022, FASOM predicts ethanol byproducts used in feed would increase 19% to 30 million tons, compared to 25 million tons under the Reference Case.

TABLE IX.A.3–2—PERCENT CHANGE IN ETHANOL BYPRODUCTS USE IN FEED RELATIVE TO THE REFERENCE CASE

Category	2022
Ethanol Byproducts	19%

The EISA cellulosic ethanol requirements result in the production of residual agriculture products as well as dedicated energy crops. By 2022, FASOM predicts production of 90 million tons of corn residue and 18 million tons of switchgrass. Sugarcane bagasse for cellulosic ethanol production increases by 15.7 million tons to 19.7 million tons in 2022 relative to the Reference Case.

4. U.S. Land Use Changes

Higher U.S. corn prices would have a direct impact on the value of U.S. agricultural land. As demand for corn and other farm products increases, the price of U.S. farm land would also increase. Our analysis shows that land prices would increase by about 21% by 2022, relative to the Reference Case. FASOM estimates an increase of 3.2 million acre increase (3.9%) in harvested corn acres, relative to 83.4 million acres harvested under the Reference Case by 2022.[477] Most of the new corn acres come from a reduction in existing crop acres, such as rice, wheat, and hay.

Though demand for biodiesel increases, FASOM predicts a fall in U.S. soybean acres harvested, assuming soybean-based biodiesel meets the EISA GHG emission reduction thresholds. According to the model, harvested soybean acres would decrease by approximately 0.4 million acres (−0.5%), relative to the Reference Case acreage of 71.5 million acres in 2022. Despite the decrease in soybean acres in 2022, soybean oil production would increase by 0.4 million tons (4.0%) by 2022 over the Reference Case. Additionally, FASOM predicts that soybean oil exports would decrease 1.3 million tons by 2022 (−52%) relative to the Reference Case.

As the demand for cellulosic ethanol increases, most of the production is derived from corn residue harvesting. As demand for cellulosic ethanol from bagasse increases, sugarcane acres increase by 0.7 millions acres (55%) to 1.9 million acres by 2022. In addition, some of the cellulosic ethanol comes from switchgrass, which is not produced under the Reference Case. In the scenario analyzed, 2.8 million acres of switchgrass will be planted by 2022. As described in Section V, for both the Reference Case and the Control Case, we assume 32 million acres would remain in the Conservation Reserve Program (CRP). Therefore, some of the new corn, soybean, and switchgrass acres may be indirectly coming from former CRP land that is not re-enrolled in the program.

[477] Total U.S. planted acres increases to 92.2 million acres from the Reference Case level of 89 million acres in 2022.

TABLE IX.A.4–1—CHANGE IN U.S. CROP ACRES RELATIVE TO THE REFERENCE CASE IN 2022

[Millions of acres]

Crop	Change	% Change
Corn	3.2	3.9
Soybeans	−0.4	−0.5
Sugarcane	0.7	55
Switchgrass	2.8	N/A

The additional demand for corn and other crops for biofuel production also results in increased use of fertilizer in the U.S. In 2022, FASOM estimates that U.S. nitrogen fertilizer use would increase 897 million pounds (3.4%) over the Reference Case nitrogen fertilizer use of 26.2 billion pounds. In 2022, U.S. phosphorous fertilizer use would increase by 496 million pounds (8.6%) relative to the Reference Case level of 5.8 billion pounds.

TABLE IX.A.4–2—CHANGE IN U.S. FERTILIZER USE RELATIVE TO THE REFERENCE CASE

[Millions of pounds]

Fertilizer	Change	% Change
Nitrogen	897	3.4
Phosphorous	496	8.6

5. Impact on U.S. Food Prices

Due to higher commodity prices, FASOM estimates that U.S. food costs [478] would increase by roughly $10 per person per year by 2022, relative to the Reference Case.[479] Total effective farm gate food costs would increase by $3.3 billion (0.2%) in 2022.[480] To put these changes in perspective, average U.S. per capita food expenditures in 2007 were $3,778 or approximately 10% of personal disposable income. The total amount spent on food in the U.S. in 2007 was $1.14 trillion dollars.[481]

6. International Impacts

Changes in the U.S. agriculture economy are likely to have effects in other countries around the world in terms of trade, land use, and the global price and consumption of fuel and food. We utilized the FAPRI model to assess the impacts of the increased use of renewable fuels in the U.S. on world agricultural markets.

The FAPRI modeling shows that world corn prices would increase by 7.5% to $3.69 per bushel in 2022, relative to the Reference Case. The impact on world soybean prices is somewhat smaller, increasing 5.6% to $9.94 per bushel in 2022.

Changes to the global commodity trade markets and world commodity prices result in changes in international land use. The FAPRI model provides international change in crop acres as a result of the RFS2 proposal. Brazil has the largest positive change in crop acres in 2022, followed by the U.S., Nigeria, India, Paraguay, and China. The FAPRI model estimates that Brazil crop acres increase by 3.1 million acres (2.0%) to 153.6 million acres relative to the Reference Case. Total U.S. acres increase by 2.3 million acres (1.0%) in 2022 to 232.6 million acres. Nigeria has an increase in crop acres of 1.5 million acres (5.9%) to 27.3 million acres in 2022. India's total crop acres increase by 1.0 million acres (0.3%) to 326 million acres in 2022. Total crop acres in Paraguay increase by 0.8 million acres (6.9%) to 12 million acres. China's total crop acres increase by 0.4 million acres (0.2%) to 257.8 million acres in 2022.

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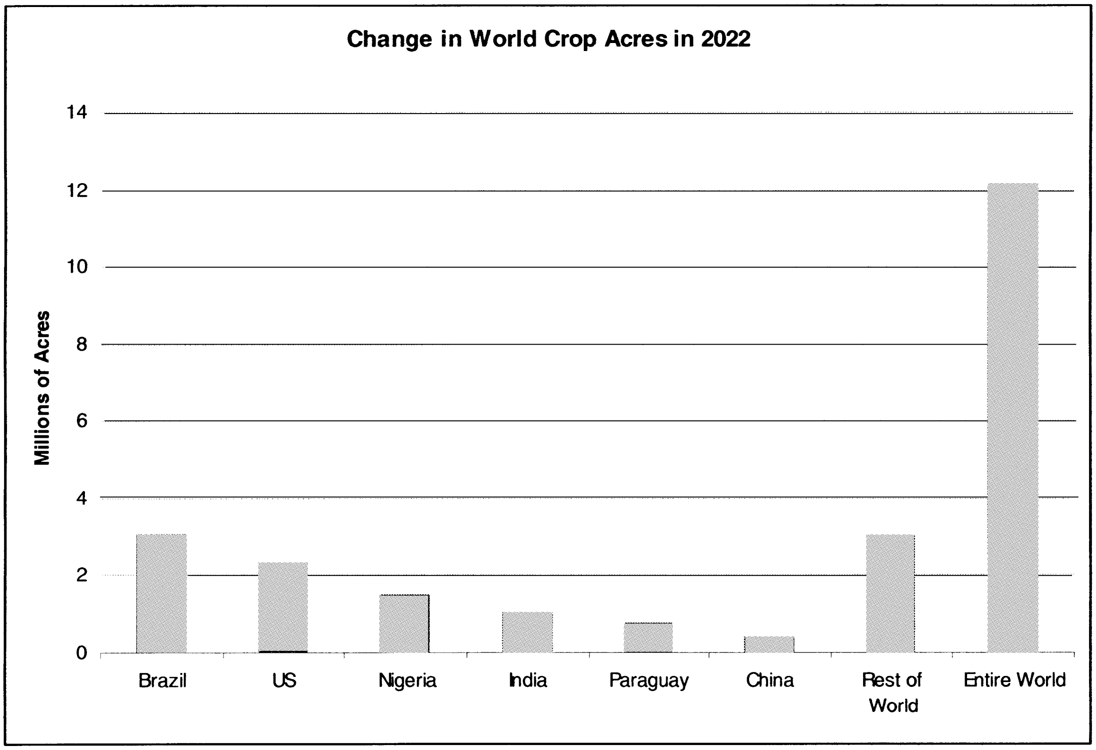
[478] FASOM does not calculate changes in price to the consumer directly. The proxy for aggregate food price change is an indexed value of all food prices at the farm gate. It should be noted, however, that according to USDA, approximately 80% of consumer food expenditures are a result of handling after it leaves the farm (e.g., processing, packaging, storage, marketing, and distribution). These costs consist of a complex set of variables, and do not necessarily change in proportion to an increase in farm gate costs. In fact, these intermediate steps can absorb price increases to some extent, suggesting that only a portion of farm gate price changes are typically reflected at the retail level. *See http://www.ers.usda.gov/publications/foodreview/septdec00/FRsept00e.pdf.*

[479] These estimates are based on U.S. Census population projections of 318 million people in 2017 and 330 million people in 2022. *See http://www.census.gov/population/www/projections/natsum.html.*

[480] Farm Gate food prices refer to the prices that farmers are paid for their commodities.

[481] *See* www.ers.usda.gov/Briefing/CPIFoodAndExpenditures/Data/table15.htm.

Figure IX.A.6-1
Change in World Crop Acres By Country in 2022
(millions of acres)



The RFS2 proposal results in higher international commodity prices, which would impact world food consumption.[482] The FAPRI model indicates that world consumption of corn for food would decrease by 1.1 million metric tons in 2022 relative to the Reference Case. Similarly, the FAPRI model estimates that world consumption of wheat for food would decrease by 0.6 million metric tons in 2022. World consumption of oil for food (e.g., vegetable oils) decreases 1.8 million metric tons by 2022. The model also estimates a small change in world meat consumption, decreasing by 0.3 million metric tons in 2022. When considering all the food uses included in the model, world food consumption decreases by 0.9 million metric tons by 2022 (−0.04%). While FAPRI provides estimates of changes in world food consumption, estimating effects on global nutrition is beyond the scope of this analysis.

TABLE IX.A.6–1—CHANGE IN WORLD FOOD CONSUMPTION RELATIVE TO THE REFERENCE CASE

[Millions of metric tons]

Category	2022
Corn	−1.1
Wheat	−0.6
Vegetable Oils	−1.8
Meat	−0.3
Total Food	−0.9

Additional information on the U.S. agricultural sector and international trade impacts of this proposal is described in more detail in the DRIA (Chapter 5).

B. Energy Security Impacts

Increasing usage of renewable fuels helps to reduce U.S. petroleum imports. A reduction of U.S. petroleum imports reduces both financial and strategic risks associated with a potential disruption in supply or a spike in cost of a particular energy source. This reduction in risks is a measure of improved U.S. energy security. In this section, we estimate the monetary value of the energy security benefits of the RFS2 mandated volumes in comparison to the Reference Case by estimating the impact of the expanded use of renewable fuels on U.S. oil imports and avoided U.S. oil import expenditures. In the second section, a methodology is described for estimating the energy security benefits of reduced U.S. oil imports. The final section summarizes the energy security benefits to the U.S. associated with this proposal.

1. Implications of Reduced Petroleum Use on U.S. Imports

In 2007, U.S. petroleum imports represented 19.5% of total U.S. imports of all goods and services.[483] In 2005, the United States imported almost 60% of the petroleum it consumed. This compares roughly to 35% of petroleum from imports in 1975.[484] Transportation accounts for 70% of the U.S. petroleum consumption. It is clear that petroleum imports have a significant impact on the U.S. economy. Diversifying transportation fuels in the U.S. is expected to lower U.S. petroleum imports. To estimate the impacts of this proposal on the U.S.'s dependence on

[482] The food commodities included in the FAPRI model include corn, wheat, sorghum, barley, soybeans, sugar, peanuts, oils, beef, pork, poultry, and dairy products.

[483] Bureau of Economic Affairs: "U.S. International Transactions, Fourth Quarter of 2007" by Elena L. Nguyen and Jessica Melton Hanson, April 2008.

[484] Davis, Stacy C.; Diegel, Susan W., *Transportation Energy Data Book: 25th Edition,* Oak Ridge National Laboratory, U.S. Department of Energy, ORNL–6974, 2006.

imported oil, we calculate avoided U.S. expenditures on petroleum imports.

For the proposal, EPA analyzed two approaches to estimate the reductions in U.S. petroleum imports. The first approach utilizes a model of the U.S. energy sector, the National Energy Modeling System (NEMS), to quantify the type and volume of reduced petroleum imports based on supply and demand for specific fuels in a given year. The National Energy Modeling System (NEMS) is a computer-based, energy-economy modeling system of U.S. energy markets through the 2030 time period. NEMS projects U.S. production, imports, conversion, consumption, and prices of energy; subject to assumptions on world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. NEMS is designed and implemented by the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE). For this analysis, the NEMS model was run with the 2007 AEO levels of biofuels in the Reference Case compared with the biofuel volume RFS2 requirements.

Considering the regional nature of U.S. imports of petroleum imports, a second approach was utilized as well to estimate the impacts of the RFS2 proposal on U.S. oil imports. This approach is labeled ''Regional Gasoline Market'' approach. This approach makes the assumption that one half of the ethanol market is in the Northeast region of the U.S., which also comprises about half of the nation's gasoline demand. For this analysis, it is estimated that ethanol would displace imported gasoline or gasoline blend stocks in the Northeast, but not elsewhere in the country. Therefore, to derive the portion of the new renewable fuels which would offset U.S. petroleum imports (and not impact domestic refinery production), we multiplied the total volume of petroleum fuel displaced by 50 percent to represent that portion of the ethanol which would be used in the Northeast, and 50 percent again to only account for that which would offset imports. The rest of the ethanol, including half of the ethanol presumed to be used in the Northeast, is presumed to offset domestic gasoline production, which ultimately offsets crude oil inputs at refineries. Biodiesel and renewable diesel are presumed to offset domestic diesel fuel production.

The results shown in Table IX.B.1–1 below reflect the net lifecycle reductions in U.S. oil imports projected by NEMS. The net lifecycle reductions include the upstream petroleum used to produce renewable fuels, gasoline and diesel, as well as the petroleum directly used by end-users.

TABLE IX.B.1–1—NET REDUCTIONS IN OIL IMPORTS IN 2022 (NEMS MODEL RESULTS)

[Millions of barrels per day]

Category of reduction	2022
Imports of Finished Petroleum Products	0.823
Imports of Crude Oil	(0.007)
Total Reduction	0.815
Percent Reduction	6.15%

The NEMS model projects that for the year 2022 all of the reduction in petroleum imports comes out of finished petroleum products. NEMS projects that 91% of the reductions in 2022 come from reduced net imports of crude oil and finished petroleum products (as compared to a 9% reduction in domestic U.S. production).

The results shown in Table IX.B.1–2 below reflect the net lifecycle reductions in U.S. oil imports projected by the use of the Regional Gasoline Market approach detailed above.

TABLE IX.B.1–2—NET REDUCTIONS IN OIL IMPORTS IN 2022 (REGIONAL GASOLINE MARKET APPROACH RESULTS)

[Millions of barrels per day]

Category of reduction	2022
Imports of Finished Petroleum Products	0.250
Imports of Crude Oil	0.637
Total Reduction	0.887
Percent Reduction	6.17%

The Regional Gasoline Market approach projects that for 2022, 72% of the petroleum supply displacement (on a volume basis) comes out of reduced net crude oil imports, and 28% out of net imports of finished petroleum products (excluding biofuels). Using our two approaches for projecting total petroleum import reductions (the NEMS and the Regional Gasoline Market), we estimate that petroleum product imports will fall between 0.815 to 0.887 million barrels per day in 2022 as a result of the RFS2 proposal.

Using the NEMS model, we also calculated the change in expenditures in both U.S. petroleum and ethanol imports with the RFS2 proposal and compared these with the U.S. trade position measured as U.S. net exports of all goods and services economy-wide. Changes in fuel expenditures were estimated by multiplying the changes in gasoline, diesel, and ethanol net imports by the respective AEO 2008 wholesale gasoline and distillate price forecasts, and ethanol price forecasts from the Food and Agricultural Policy Research Institute (FAPRI) for the specific analysis years. In Table IX.B.1–3, the net expenditures in reduced petroleum imports and increased ethanol imports are compared to the total value of U.S. net exports of goods and services for the whole economy for 2022. The U.S. net exports of goods and services estimates are taken from Energy Information Administration's Annual Energy Outlook 2008. We project that avoided expenditures on imported petroleum products due to this proposal would be roughly $16 billion in 2022. Relative to the 2022 projection, the total avoided expenditures on liquid transportation fuels are projected to be $12.4 billion with the RFS2 proposal.

TABLE IX.B.1–3—CHANGES IN EXPENDITURES ON TRANSPORTATION FUEL NET IMPORTS

[Billions of 2006$]

Category	2022
AEO Total Net Exports	16
Expenditures on Net Petroleum Imports	(15.96)
Expenditures on Net Ethanol and Biodiesel Imports	3.52
Net Expenditures on Transportation Fuel Imports	(12.44)

2. Energy Security Implications

In order to understand the energy security implications of reducing U.S. oil imports, EPA has worked with Oak Ridge National Laboratory (ORNL), which has developed approaches for evaluating the social costs and energy security implications of oil use. In a new study entitled *''The Energy Security Benefits of Reduced Oil Use, 2006–2015,''* completed in February, 2008, ORNL has updated and applied the analytical approach used in the 1997 Report *''Oil Imports: An Assessment of Benefits and Costs.''* [485] [486] This new study is included as part of the record in this rulemaking.[487]

[485] Leiby, Paul N., Donald W. Jones, T. Randall Curlee, and Russell Lee, *Oil Imports: An Assessment of Benefits and Costs*, ORNL–6851, Oak Ridge National Laboratory, November, 1997.

[486] The 1997 ORNL paper was cited and its results used in DOT/NHTSA's rules establishing CAFE standards for 2008 through 2011 model year light trucks. *See* DOT/NHTSA, Final Regulatory Impacts Analysis: Corporate Average Fuel Economy and CAFE Reform MY 2008–2011, March 2006.

[487] Leiby, Paul N. ''Estimating the Energy Security Benefits of Reduced U.S. Oil Imports,'' Oak Ridge

Continued

The approach developed by ORNL estimates the incremental benefits to society, in dollars per barrel, of reducing U.S. oil imports, called the ''oil premium.'' Since the 1997 publication of the ORNL Report, changes in oil market conditions, both current and projected, suggest that the magnitude of the oil premium has changed. Significant driving factors that have been revised include: Oil prices, current and anticipated levels of OPEC production, U.S. import levels, the estimated responsiveness of regional oil supplies and demands to price, and the likelihood of oil supply disruptions. For this analysis, oil prices from the AEO 2007 were used. Using the ''oil premium'' approach, the analysis calculates estimates of benefits of improved energy security from reduced U.S. oil imports due to this proposal.

When conducting this analysis, ORNL considered the full economic cost of importing petroleum into the U.S. The full economic cost of importing petroleum into the U.S. is defined for this analysis to include two components in addition to the purchase price of petroleum itself. These are: (1) The higher costs for oil imports resulting from the effect of U.S. import demand on the world oil price and OPEC market power (i.e., the ''demand'' or ''monopsony'' costs); and (2) the risk of reductions in U.S. economic output and disruption of the U.S. economy caused by sudden disruptions in the supply of imported oil to the U.S. (i.e., macroeconomic disruption/adjustment costs). Maintaining a U.S. military presence to help secure stable oil supply from potentially vulnerable regions of the world was excluded from this analysis because its attribution to particular missions or activities is difficult.

Also excluded from the prior analysis was risk-shifting that might occur as the U.S. reduces its dependency on petroleum and increases its use of biofuels. The analysis to date focused on the potential for biofuels to reduce oil imports, and the resulting implications of lower imports for energy security. The Agency recognizes that as the U.S. relies more heavily on biofuels, such as corn-based ethanol, there could be adverse consequences from a supply-disruption associated with, for example, a long-term drought. While the causal factors of a supply-disruption from imported petroleum and, alternatively, biofuels, are likely to be unrelated, diversifying the sources of U.S. transportation fuel will provide energy security benefits. The Agency was not able to conduct an analysis of biofuel supply disruption issue for this proposal.

National Laboratory, ORNL/TM–2007/028, Final Report, 2008.

Between today's proposal and the final rulemaking, EPA will attempt to broaden our energy security analysis to incorporate estimates of overall motor fuel supply and demand flexibility and reliability, and impacts of possible agricultural sector market disruptions (for example, a drought) for presentation in the final rule. The expanded analysis will also consider how the use of biofuels can alter short and long run elasticity (flexibility) in the motor fuel market, with implications for robustness of the fuel system in the face of diverse supply shocks. As part of this analysis, the Agency plans on analyzing those factors that can cause shifts in the prices of biofuels, and the impact these factors have on the energy security estimate.

EPA sponsored an independent-expert peer review of the most recent ORNL study. A report compiling the peer reviewers' comments is provided in the docket.[488] In addition, EPA has worked with ORNL to address comments raised in the peer review and develop estimates of the energy security benefits associated with a reduction in U.S. oil imports for this proposal. In response to peer reviewer comments, EPA modified the ORNL model by changing several key parameters involving OPEC supply behavior, the responsiveness of oil demand and supply to a change in the world oil price, and the responsiveness of U.S. economic output to a change in the world oil price. EPA is soliciting comments on how to incorporate additional peer reviewer comments into the ORNL energy security analysis. (*See* the DRIA, Chapter 5, for more information on how EPA responded to peer reviewer comments.)

With these changes for this proposal, ORNL has estimated that the total energy security benefits associated with a reduction of imported oil is $12.38/barrel. Based upon alternative sensitivities about OPEC supply behavior and the responsiveness of oil demand and supply to a change in the world oil price, the energy security premium ranged from $7.65 to $17.23/barrel. Highlights of the analysis are described below.

[488] *Peer Review Report Summary: Estimating the Energy Security Benefits of Reduced U.S. Oil Imports*, ICF, Inc., September 2007.

a. Effect of Oil Use on Long-Run Oil Price, U.S. Import Costs, and Economic Output

The first component of the full economic costs of importing petroleum into the U.S. follows from the effect of U.S. import demand on the world oil price over the long-run. Because the U.S. is a sufficiently large purchaser of foreign oil supplies, its purchases can affect the world oil price. This monopsony power means that increases in U.S. petroleum demand can cause the world price of crude oil to rise, and conversely, that reduced U.S. petroleum demand can reduce the world price of crude oil. Thus, one benefit of decreasing U.S. oil purchases is the potential decrease in the crude oil price paid for all crude oil purchased. ORNL estimates this component of the energy security benefit to be $7.65/barrel of U.S. oil imports reduced. A number of the peer reviewers suggested a variety of ways OPEC and other oil market participants might react to a decrease in the quantity of oil purchased by the U.S. ORNL has attempted to reflect a variety of possible market reactions in the analysis, but continues to evaluate ways to more explicitly model OPEC and other market participants' behavior. EPA welcomes comments on this issue. Based upon alternative sensitivities about OPEC supply behavior, the price-responsiveness of combined non-OPEC, non-U.S. supply and demand and a lower GDP elasticity with respect to disrupted oil prices, the monopsony premium ranged from $3.35–$12.45/barrel of U.S. imported oil reduced.

EPA recognizes that as the world price of oil falls in response to lower U.S. demand for oil, there is the potential for an increase in oil use outside the U.S. This so-called international oil ''take back'' or ''rebound'' effect is hard to estimate. Given that oil consumption patterns vary across countries, there will be different demand responses to a change in the world price of crude oil. For example, in Europe, the price of crude oil comprises a much smaller portion of the overall fuel prices seen by consumers than in the U.S. Since Europeans pay significantly more than their U.S. counterparts for transportation fuels, a decline in the price of crude oil is likely to have a smaller impact on demand. In many other countries, particularly developing countries, such as China and India, oil is used more widely in industrial and even electricity applications, although China and India's energy picture is evolving rapidly. In addition, many countries around the world subsidize their oil consumption. It is not clear how oil consumption would change due to changes in the market price of oil with the current pattern of subsidies. Emerging trends in worldwide oil consumption patterns illustrates the difficulty in trying to estimate the overall effect of a reduction in world oil price. However, the Agency recognizes that this effect is important to capture and is examining methodologies for quantifying this effect. EPA is exploring the development of this effect at the regional and country level in an effort to capture the net effect of different drivers. For example, a lower world oil price might encourage consumption of oil, but a country might deploy programs and policies discouraging oil consumption, which would have the net effect of lowering oil consumption to some level less than otherwise would be expected. EPA solicits comments on how to estimate this effect.

b. Short-Run Disruption Premium From Expected Costs of Sudden Supply Disruptions

The second component of the external economic costs resulting from U.S. oil imports arises from the vulnerability of the U.S. economy to oil shocks. The cost of shocks depends on their likelihood, size, and length; the capabilities of the market and U.S. Strategic Petroleum Reserve (SPR), the largest stockpile of government-owned emergency crude oil in the world, to respond; and the sensitivity of the U.S. economy to sudden price increases. While the total vulnerability of the U.S. economy to oil price shocks depends on the levels of both U.S. petroleum consumption and imports, variation in import levels or demand flexibility can affect the magnitude of potential increases in oil price due to supply disruptions. Disruptions are uncertain events, so the costs of alternative possible disruptions are weighted by disruption probabilities. The probabilities used by the ORNL study are based on a 2005 Energy Modeling Forum [489] synthesis of expert judgment and are used to determine an expected value of disruption costs, and the change in those expected costs given reduced U.S. oil imports. ORNL estimates this component of the energy security benefit to be $4.74/barrel of U.S. imported oil reduced. Based upon alternative sensitivities about OPEC supply behavior, the price-responsiveness of combined non-OPEC, non-U.S. supply and demand and a lower GDP elasticity with respect to disrupted oil prices, the macroeconomic disruption premium ranged from $2.64–$6.96/barrel of U.S. imported oil reduced. EPA continues to review recent literature on the macroeconomic disruption premium and welcomes comment on this issue.

c. Costs of Existing U.S. Energy Security Policies

Another often-identified component of the full economic costs of U.S. oil imports is the cost to the U.S. taxpayers of existing U.S. energy security policies. The two primary examples are maintaining a military presence to help secure stable oil supply from potentially vulnerable regions of the world and maintaining the SPR to provide buffer supplies and help protect the U.S. economy from the consequences of global oil supply disruptions.

U.S. military costs are excluded from the analysis performed by ORNL because their attribution to particular missions or activities is difficult. Most military forces serve a broad range of security and foreign policy objectives. Attempts to attribute some share of U.S. military costs to oil imports are further challenged by the need to estimate how those costs might vary with incremental variations in U.S. oil imports. Similarly, while the costs for building and maintaining the SPR are more clearly related to U.S. oil use and imports, historically these costs have not varied in response to changes in U.S. oil import levels. Thus, while SPR is factored into the ORNL analysis, the cost of maintaining the SPR is excluded.

A majority of the peer reviewers agreed with the exclusion of military expenditures from the current premium analysis primarily because of the difficulty in defining and measuring how military programs and expenditures might respond to incremental changes in U.S. oil imports. One reviewer clearly opposed including military costs on principle, and one peer reviewer clearly supported their inclusion if they could be shown to vary with import levels. The matter of whether military needs and programs can and do vary with U.S. oil imports or consumption levels would require careful consideration and analysis. It also calls for expertise in areas outside the scope of the peer review such as national security and military affairs. EPA solicits comment in this area.

d. Anticipated Future Effort

Between the proposal and the final rule, EPA intends to undertake a variety of actions to improve its energy security premium estimates. For the monopsony premium, we intend to develop energy security premiums with alternative AEO oil price cases (e.g., Reference, High, Low), develop a dynamic analysis methodology (i.e., how the energy security premium evolves through time), and assess and apply literature on OPEC strategic behavior/gaming models where possible. For the macroeconomic disruption impacts, EPA intends to examine recent literature on the elasticity of GDP to the oil price. Based upon that literature review, we intend to determine whether there is a difference in macro disruption impacts in the pre-2000 and post-2000 time period. Further, we intend to break down the macroeconomic disruption costs by GDP losses and oil import costs.

EPA solicits comments on the energy security analysis in a number of areas. Specifically, EPA is requesting comment on its interpretation of ORNL's results, ORNL's methodology, the monopsony effect, and the macroeconomic disruption effect.

e. Total Energy Security Benefits

Total annual energy security benefits associated with this proposal were derived from the estimated reductions in imports of finished petroleum products and crude oil using an energy security premium price of $12.38/barrel of reduced U.S. oil imports. Based on these values, we estimate that the total annual energy security benefits would be $3.7 billion in 2022 (in 2006 dollars).

C. Benefits of Reducing GHG Emissions

1. Introduction

The wider use of renewable fuels from this proposal results in reductions in greenhouse gas (GHG) emissions. Carbon dioxide (CO_2) and other GHGs mix well in the atmosphere, regardless of the location of the source, with each unit of emissions affecting global regional climates; and therefore, influencing regional biophysical systems. The effects of changes in GHG emissions are felt for decades to centuries given the atmospheric lifetimes of GHGs. This section provides estimates for the marginal and total benefits that could be monetized for the projected GHG emissions reductions of the proposal. EPA requests comment on the approach utilized to estimate the GHG benefits associated with the proposal.

2. Marginal GHG Benefits Estimates

The projected net GHG emissions reductions associated with the proposal reflect an incremental change to projected total global emissions.

[489] Stanford Energy Modeling Forum, Phillip C. Beccue and Hillard G. Huntington, ''An Assessment of Oil Market Disruption Risks,'' Final Report, EMF SR 8, October, 2005.

Therefore, as shown in Section VI.G, the projected global climate signal will be small but discernable (i.e., incrementally lower projected distribution of global mean surface temperatures). Given that the climate response is projected to be a marginal change relative to the baseline climate, it is conceptually appropriate to use an approach that estimates the marginal value of changes in climate change impacts over time as an estimate for the monetized marginal benefit of the GHG emissions reductions projected for this proposal. The marginal value of carbon is equal to the net present value of climate change impacts over hundreds of years of one additional net global metric ton of GHGs emitted to the atmosphere at a particular point in time. This marginal value (i.e., cost) of carbon is sometimes referred to as the ''social cost of carbon.''

Based on the global implications of GHGs and the economic principles that follow, EPA has developed ranges of global, as well as U.S., *marginal* benefits estimates (Table IX.C.2–1).[490] It is important to note at the outset that the estimates are incomplete since current methods are only able to reflect a partial accounting of the climate change impacts identified by the IPCC (discussed more below). Also, domestic estimates omit potential impacts on the United States (e.g., economic or national security impacts) resulting from climate change impacts in other countries. The global estimates were developed from a survey analysis of the peer reviewed literature (i.e., meta analysis). U.S. estimates, and a consistent set of global estimates, were developed from a single model and are highly preliminary, under evaluation, and likely to be revised. The latter set of estimates was developed because the peer reviewed literature does not currently provide regional (i.e., at the U.S. or China level) marginal benefits estimates, and it was important to have a consistent set of regional and global estimates. Ranges of estimates are provided to capture some of the uncertainties associated with modeling climate change impacts.

The range of estimates is wide due to the uncertainties relating to socio-economic futures, climate responsiveness, impacts modeling, as well as the choice of discount rate. For instance, for 2007 emission reductions and a 2% discount rate the global meta analysis estimates range from $\$-3$ to \$159/tCO_2, while the U.S. estimates range from \$0 to \$16/tCO_2. For 2007 emission reductions and a 3% discount rate, the global meta-estimates range from $\$-4$ to \$106/tCO_2, and the U.S. estimates range from \$0 to \$5/tCO_2.[491] The global meta analysis mean values for 2007 emission reductions are \$68 and \$40/tCO_2 for discount rates of 2% and 3%, respectively (in 2006 real dollars), while the domestic mean value from a single model are \$4 and \$1/tCO_2 for the same discount rates. The estimates for future year emission changes will be higher as future marginal emissions increases are expected to produce larger incremental damages as physical and economic systems become more stressed as the magnitude of climate change increases.[492]

TABLE IX.C.2–1—MARGINAL GHG BENEFITS ESTIMATES FOR DISCOUNT RATES OF 2%, 3%, AND 7% AND YEAR OF EMISSIONS CHANGE IN 2022

[All values are reported in 2006\$/tCO_2]

	2%			3%			7% [b]		
	Low	Central	High	Low	Central	High	Low	Central	High
Meta global	−2	105	247	−2	62	165	n/a	n/a	n/a
FUND global	−4	136	1083	−4	26	206	−2	−1	9
FUND domestic	[a] 0	7	26	[a] 0	2	9	[a] 0	[a] 0	[a] 0

[a] These estimates, if explicitly estimated, may be greater than zero, especially in later years. They are currently reported as zero because the explicit estimates for an earlier year were zero and were grown at 3% per year. However, we do not anticipate that the explicit estimates for these later years would be significantly above zero given the magnitude of the current central estimates for discount rates of 2% and 3% and the effect of the high discount rate in the case of 7%.

[b] Except for illustrative purposes, the marginal benefits estimates in the peer reviewed literature do not use consumption discount rates as high as 7%.

The meta analysis ranges were developed from the Tol (2008) meta analysis. The meta analysis range only includes global estimates generated by more recent peer reviewed studies (i.e., published after 1995). In addition, the ranges only consider regional aggregations using simple summation and intergenerational consumption discount rates of approximately 2% and 3%.[493] Discount rates of 2% and 3% are consistent with EPA and OMB guidance on intergenerational discount rates (EPA, 2000; OMB, 2003).[494] The estimated distributions of the meta global estimates are right skewed with long right tails, which is consistent with characterizations of the low probability high impact damages (see the DRIA for the estimated probability density functions by discount rate).[495] The central meta estimates in Table IX.C.2–1 are means, and the low and high are the 5th and 95th percentiles. Means are

[490] For background on economic principles and the marginal benefit estimates, *see Technical Support Document on Benefits of Reducing GHG Emissions,* U.S. Environmental Protection Agency, June 12, 2008, *www.regulations.gov* (search phrase ''Technical Support Document on Benefits of Reducing GHG Emissions'').

[491] See Table IX.C.1 for global (FUND) estimates consistent with the U.S. estimates.

[492] The IPCC suggests an increase of 2–4% per year (IPCC WGII, 2007. *Climate Change 2007—Impacts, Adaptation and Vulnerability.* Contribution of Working Group II to the Fourth Assessment Report of the IPCC, *http://www.ipcc.ch/*). For Table IX.C.1., we assumed the estimates increased at 3% per year. For the final rule, we anticipate that we will explicitly estimate FUND marginal benefits values for each emissions reduction year.

[493] Tol (2008) is an update of the Tol (2005) meta analysis. Tol (2005) was used in the IPCC Working Group II's Fourth Assessment Report (IPCC WGII, 2007).

[494] OMB and EPA guidance on inter-generational discounting suggests using a low but positive discount rate if there are important intergenerational benefits/costs. Consumption discount rates of 1–3% are given by OMB and 0.5–3% by EPA (OMB Circular A–4, 2003; EPA Guidelines for Preparing Economic Analyses, 2000).

[495] E.g., Webster, M., C. Forest, J.M. Reilly, M.H. Babiker, D.W. Kicklighter, M. Mayer, R.G. Prinn, M. Sarofim, A.P. Sokolov, P.H. Stone & C. Wang, 2003. Uncertainty Analysis of Climate Change and Policy Response, Climatic Change 61(3): 295–320. Also, see Weitzman, M., 2007, ''The Stern Review of the Economics of Climate Change,'' *Journal of Economic Literature.* Weitzman, M., 2007, ''Structural Uncertainty and the Statistical Life in the Economics of Catastrophic Climate Change,'' Working paper *http://econweb.fas.harvard.edu/faculty/weitzman/papers/ValStatLifeClimate.pdf.*

presented because, as a central statistic, they better represent the skewed shape of these distributions compared to medians.

The consistent domestic and global estimates were developed using the FUND integrated assessment model (i.e., the Climate Framework for Uncertainty, Negotiation, and Distribution).[496] The ranges were generated from sensitivity analyses where we varied assumptions with respect to climate sensitivity (1.5 to 6.0 degrees Celsius),[497] the socio-economic and emissions baseline scenarios (the FUND default baseline and three baselines from the Intergovernmental Panel on Climate Change (IPCC) Special Report on Emissions Scenarios, SRES),[498] and the consumption discount rates of approximately 2%, 3%, and 7%, where 2% and 3% are consistent with intergenerational discounting.[499] Furthermore, the model was calibrated to the EPA value of a statistical life of $7.4 million (in 2006 real dollars).[500] The FUND global estimates are the sum of the regional estimates within FUND. The FUND global and domestic central values in Table IX.C.2–1 are weighted averages of the FUND estimates from the sensitivity analysis (see the DRIA for details). The low and high values are the low and high estimates across the sensitivity runs.

From Table IX.C.2–1, we see that, in terms of the current monetized benefits, the domestic marginal benefits are a fraction of the global marginal benefits. Given uncertainties and omitted impacts, it is difficult to estimate the actual ratio of total domestic benefits to total global benefits. The estimates suggest that an emissions reduction will have direct benefits for current and future U.S. populations and large benefits for global populations. The long-run and intergenerational implications of GHG emissions are evident in the difference in results across discount rates. In the current modeling, there are substantial long-run benefits (beyond the next two decades to over 100 years) and some near-term benefits as well as negative effects (e.g., agricultural productivity and heating demand). High discount rates give less weight to the distant benefits in the net present value calculations, and more weight to near-term effects. While not obvious in Table IX.C.2–1, an additional unit of emissions in the higher climate sensitivity scenarios, versus the lower climate sensitivity scenarios, is estimated to have a proportionally larger effect on the rest of the world compared to the U.S. (see more detailed results in DRIA). These points are discussed more below.

3. Discussion of Marginal GHG Benefits Estimates

This section briefly discusses important issues relevant to the marginal benefits estimates in Table IX.C.2–1 (see the DRIA for more extensive discussion). The broad range of estimates in Table IX.C.2–1 reflects some of the uncertainty associated with estimating monetized marginal benefits of climate change. The meta analysis range reflects differences in these assumptions as well as differences in the modeling of changes in climate and impacts considered and how they were modeled. EPA considers the meta analysis results to be more robust than the single model estimates in that the meta results reflect uncertainties in both models and assumptions.

The current state-of-the-art for estimating benefits is important to consider when evaluating policies. There are significant partially unquantified and omitted impact categories not captured in the estimates provided above. The IPCC WGII (2007) concluded that current estimates are ''very likely'' to be underestimated because they do not include significant impacts that have yet to be monetized.[501] Current estimates do not capture many of the main reasons for concern about climate change, including nonmarket damages (e.g., species existence value and the value of having the option for future use), the effects of climate variability, risks of potential extreme weather (e.g., droughts, heavy rains and wind), socially contingent effects (such as violent conflict or humanitarian crisis), and thresholds (or tipping points) associated with species, ecosystems, and potential long-term catastrophic events (e.g., collapse of the West Antarctic Ice Sheet, slowing of the Atlantic Ocean Thermohaline Circulation). Underestimation is even more likely when one considers that the current trajectory for GHG emissions is higher than typically modeled, which when combined with current regional population and income trajectories that are more asymmetric than typically modeled, imply greater climate change and vulnerability to climate change. See the DRIA for an initial, partial list of impacts that are currently not modeled in the FUND model and are thus not reflected in the FUND estimates. EPA is planning to develop a full assessment of what is not currently being captured in FUND for the final rule. In addition, EPA plans to quantify omitted impacts and update impacts currently represented to the maximum extent possible for the final rule.

The current estimates are also deterministic in that they do not account for the value people have for changes in risk due to changes in the likelihood of potential impacts associated with reductions in CO_2 and other GHG emissions (i.e., a risk premium). This is an issue that has concerned Weitzman and other economists.[502] We plan to conduct a formal uncertainty analysis for the final rule to attempt to account for, to the extent possible, these and other changes in uncertainty.

The estimates in Table IX.C.2–1 are only relevant for incremental policies relative to the projected baselines (that do not reflect potential future climate policies) and there is substantial uncertainty associated with the estimates themselves both in terms of what is being modeled and what is not being modeled, with many uncertainties outside of observed variability.[503] Both

[496] FUND is a spatially and temporally consistent framework—across regions of the world (e.g., U.S., China), impacts sectors, and time. FUND explicitly models impacts sectors in 16 global regions. FUND is one of the few models in the world that explicitly models global and regional marginal benefits estimates. Numerous applications of FUND have been published in the peer reviewed literature dating back to 1997. *See http://www.fnu.zmaw.de/FUND.5679.0.html*.

[497] In IPCC reports, equilibrium climate sensitivity refers to the equilibrium change in the annual mean global surface temperature following a doubling of the atmospheric equivalent carbon dioxide concentration. The IPCC states that climate sensitivity is ''likely'' to be in the range of 2 °C to 4.5 °C and described 3 °C as a ''best estimate'', which is the mode (or most likely) value. The IPCC goes on to note that climate sensitivity is ''very unlikely'' to be less than 1.5 °C and ''values substantially higher than 4.5 °C cannot be excluded.'' IPCC WGI, 2007, Climate Change 2007—The Physical Science Basis, Contribution of Working Group I to the Fourth Assessment Report of the IPCC, *http://www.ipcc.ch/*.

[498] The IMAGE model SRES baseline data was used for the A1b, A2, and B2 scenarios (IPCC, 2000. *Special Report on Emissions Scenarios.* A special report of Working Group III of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge).

[499] The EPA guidance on intergenerational discounting states that ''[e]conomic analyses should present a sensitivity analysis of alternative discount rates, including discounting at two to three percent and seven percent as in the intra-generational case, as well as scenarios using rates in the interval one-half to three percent as prescribed by optimal growth models.'' (EPA, 2000).

[500] This number may be updated to be consistent with recent EPA regulatory impact analyses that have used a value of $6.4 million (in 2006 real dollars).

[501] IPCC WGII, 2007. In the IPCC report, ''very likely'' was defined as a greater than 90% likelihood based on expert judgment.

[502] E.g, Webster *et al.*, 2003; Weitzman, M., 2007. *http://econweb.fas.harvard.edu/faculty/weitzman/papers/ValStatLifeClimate.pdf.*

[503] Because some types of potential climate change impacts may occur suddenly or begin to

Continued

of these points are important for non-marginal emissions changes and estimating total benefits. Also, the uncertainties inherent in this kind of modeling, including the omissions of many important impacts categories, present problems for approaches attempting to identify an economically efficient level of GHG reductions and to positive net benefit criteria in general, and point to the importance of considering factors beyond monetized benefits and costs. In uncertain situations such as that associated with climate, EPA typically recommends that analysis consider a range of benefit and cost estimates, and the potential implications of non-monetized and non-quantified benefits.

Economic principles suggest that global benefits should also be considered when evaluating alternative GHG reduction policies.[504] Typically, because the benefits and costs of most environmental regulations are predominantly domestic, EPA focuses on benefits that accrue to the U.S. population when quantifying the impacts of domestic regulation. However, OMB's guidance for economic analysis of federal regulations specifically allows for consideration of international effects.[505] GHGs are global and very long-run public goods, and economic principles suggest that the full costs to society of emissions should be considered in order to identify the policy that maximizes the net benefits to society, i.e., achieves an efficient outcome (Nordhaus, 2006).[506] As such, estimates of global benefits capture more of the full value to society than domestic estimates and will result in higher global net benefits for GHG reductions when considered.[507]

Furthermore, international effects of climate change may also affect domestic benefits directly and indirectly to the extent U.S. citizens value international impacts (e.g., for tourism reasons, concerns for the existence of ecosystems, and/or concern for others); U.S. international interests are affected (e.g., risks to U.S. national security, or the U.S. economy from potential disruptions in other nations); and/or domestic mitigation decisions affect the level of mitigation and emissions changes in general in other countries (i.e., the benefits realized in the U.S. will depend on emissions changes in the U.S. and internationally). The economics literature also suggests that policies based on direct domestic benefits will result in little appreciable reduction in global GHGs (e.g., Nordhaus, 1995).[508] While these marginal benefits estimates are not comprehensive or economically optimal, the global estimates in Table IX.C.2–1 internalize a larger portion of the global and intergenerational externalities of reducing a unit of emissions.

A key challenge facing EPA is the appropriate discount rate over the longer timeframe relevant for GHGs. With the benefits of GHG emissions reductions distributed over a very long time horizon, benefit and cost estimations are likely to be very sensitive to the discount rate. When considering climate change investments, they should be compared to similar alternative investments (via the discount rate). Changes in GHG emissions—both increases and reductions—are essentially long-run investments in changes in climate and the potential impacts from climate change, which includes the potential for significant impacts from climate change, where the exact timing and magnitude of these impacts are unknown.

When there are important benefits or costs that affect multiple generations of the population, EPA and OMB allow for low but positive discount rates (e.g., 0.5–3% noted by U.S. EPA, 1–3% by OMB).[509] In this multi-generation context, the three percent discount rate is consistent with observed interest rates from long-term investments available to current generations (net of risk premiums) as well as current estimates of the impacts of climate change that reflect potential impacts on consumers. In addition, rates of three percent or lower are consistent with long-run uncertainty in economic growth and interest rates, considerations of issues associated with the transfer of wealth between generations, and the risk of high impact climate damages. Given the uncertain environment, analysis could also consider evaluating uncertainty in the discount rate (e.g., Newell and Pizer, 2001, 2003).[510]

For the final rulemaking, we will be developing and updating the FUND model as best as possible based on the latest research and peer reviewing the estimates. To improve upon our estimates, we hope to evaluate several factors not currently captured in the proposed estimates due to time constraints. For example, we will quantify additional impact categories as is possible and provide a qualitative evaluation of the implications of what is not monetized. We also plan to conduct an uncertainty analysis, consider complementary bottom-up analyses, and develop estimates of the marginal benefits associated with non-CO_2 GHGs relevant to the rule (e.g., CH_4, N_2O, and HFC–134a).[511]

EPA solicits comment on the appropriateness of using U.S. and global values in quantifying the benefits of GHG reductions and the appropriate application of benefits estimates given the state of the art and overall uncertainties. We also seek comment on our estimates of the global and U.S. marginal benefits of GHG emissions reductions that EPA has developed, including the scientific and economic foundations, the methods employed in developing the estimates, the discount

increase at a much faster rate, rather than increasing gradually or smoothly, different approaches are necessary for quantifying the benefits of ''large'' (non-incremental) versus ''small'' (incremental) reductions in global GHGs. Marginal benefits estimates, like those presented above, can be useful for estimating benefits for small changes in emissions. *See* the DRIA for additional discussion of this point. Note that even small reductions in global GHG emissions are expected to reduce climate change risks, including catastrophic risks.

[504] Recently, the National Highway Traffic Safety Administration (NHTSA) issued the final Environmental Impact Statement for their proposed rulemaking for average fuel economy standards for passenger cars and light trucks in which the preferred alternative is based upon a domestic marginal benefit estimate for carbon dioxide reductions. See Average Fuel Economy Standards, Passenger Cars and Light Trucks, MY 2011–2015, Final Environmental Impact Statement *http://www.nhtsa.dot.gov/portal/site/nhtsa/menuitem.43ac99aefa80569eea57529cdba046a0/*.

[505] OMB (2003), page 15.

[506] Nordhaus, W., 2006, ''Paul Samuelson and Global Public Goods,'' in M. Szenberg, L. Ramrattan, and A. Gottesman (eds), Samuelsonian Economics, Oxford.

[507] Both the United Kingdom and the European Commission following these economic principles in consideration of the global social cost of carbon (SCC) for valuing the benefits of GHG emission reductions in regulatory impact assessments and cost-benefit analyses (Watkiss *et al.* 2006).

[508] Nordhaus, William D. (1995). ''Locational Competition and the Environment: Should Countries Harmonize Their Environmental Policies?'' in Locational Competition in the World Economy, Symposium 1994, ed., Horst Siebert, J. C. B. Mohr (Paul Siebeck), Tuebingen, 1995.

[509] EPA (U.S. Environmental Protection Agency), 2000. Guidelines for Preparing Economic Analyses. EPA 240–R–00–003. *See* also OMB (U.S. Office of Management and Budget), 2003. Circular A–4. September 17, 2003. These documents are the guidance used when preparing economic analyses for all EPA rulemakings.

[510] Newell, R. and W. Pizer, 2001. Discounting the benefits of climate change mitigation: How much do uncertain rates increase valuations? PEW Center on Global Climate Change, Washington, DC. Newell, R. and W. Pizer, 2003. Discounting the distant future: how much do uncertain rates increase valuations? Journal of Environmental Economics and Management 46:52–71.

[511] Due to differences in atmospheric lifetime and radiative forcing, the marginal benefit values of non-CO_2 GHG reductions and their growth rates over time will not be the same as the marginal benefits of CO_2 emissions reductions (IPCC WGII, 2007).

rates considered, current and proposed future consideration of uncertainty in the estimates, marginal benefits estimates for non-CO_2 GHG emissions reductions, and potential opportunities for improving the estimates. We are also interested in comments on methods for quantifying benefits for non-incremental reductions in global GHG emissions.

Because the literature on SCC and our understanding of that literature continues to evolve, EPA will continue to assess the best available information on the social cost of carbon and climate benefits, and may adjust its approaches to quantifying and presenting information on these areas in future rulemakings.

4. Total Monetized GHG Benefits Estimates

As described in Section VI.F, annualized equivalent GHG emissions reductions associated with the RFS2 proposal in 2022 would be 160 million metric tons of CO_2 equivalent ($MMTCO_2eq$) with a 2% discount rate, and 155 and 136 $MMCO_2eq$ with discount rates of 3% and 7%, respectively. This section provides the monetized total GHG benefits estimates associated with the proposal in 2022. As discussed above in Section IX.C.3, these estimates do not include significant impacts that have yet to be monetized. Total monetized benefits in 2022 are calculated by multiplying the marginal benefits per metric ton of CO_2 in that year by the annualized equivalent emissions reductions. For the final rulemaking, we plan to separate the emissions reductions by gas and use CO_2 and non-CO_2 marginal benefits estimates. Non-CO_2 GHGs have different climate and atmospheric implications and therefore different marginal climate impacts.

Table IX.C.4–1 provides the estimated monetized GHG benefits of the proposal for 2022. The large range of values in the Table reflects some of the uncertainty captured in the range of monetized marginal benefits estimates presented in Table IX.C.2–1.[512] All values in this section are presented in 2006 real dollars.

TABLE IX.C.4–1—MONETIZED GHG BENEFITS OF THE PROPOSED RULE IN 2022

[Billion 2006$]

Marginal benefit		2%	3%	7%
Meta global	Low	−$0.3	−$0.3	n/a
	Central	16.8	9.6	n/a
	High	39.4	25.5	n/a
FUND global	Low	−0.6	−0.6	−0.3
	Central	21.7	4.0	−0.1
	High	172.8	31.9	1.2
FUND domestic	Low	0.0	0.0	0.0
	Central	1.1	0.3	0.0
	High	4.1	1.4	0.0

D. Co-pollutant Health and Environmental Impacts

This section describes EPA's analysis of the co-pollutant health and environmental impacts that can be expected to occur as a result of this renewable fuels proposal throughout the period from initial implementation through 2030. GHG emissions are predominantly the byproduct of fossil fuel combustion processes that also produce criteria and hazardous air pollutants. The fuels that are subject to the proposed standard are also significant sources of mobile source air pollution such as direct PM, NO_X, VOCs and air toxics. The proposed standard would affect exhaust and evaporative emissions of these pollutants from vehicles and equipment. They would also affect emissions from upstream sources such as fuel production, storage, and distribution and agricultural emissions. Any decrease or increase in ambient ozone, $PM_{2.5}$, and air toxics associated with the proposal would impact human health in the form of avoided or incurred premature deaths and other serious human health effects, as well as other important public health and welfare effects.

As can be seen in Section II.B, we estimate that the proposal would lead to both increased and decreased criteria and air toxic pollutant emissions. Making predictions about human health and welfare impacts based solely on emissions changes, however, is extremely difficult. Full-scale photochemical modeling is necessary to provide the needed spatial and temporal detail to more completely and accurately estimate the changes in ambient levels of these pollutants. EPA typically quantifies and monetizes the PM- and ozone-related health and environmental impacts in its regulatory impact analyses (RIAs) when possible. However, we were unable to do so in time for this proposal. EPA attempts to make emissions and air quality modeling decisions early in the analytical process so that we can complete the photochemical air quality modeling and use that data to inform the health and environmental impacts analysis. Resource and time constraints precluded the Agency from completing this work in time for the proposal. EPA will, however, provide a complete characterization of the health and environmental impacts, both in terms of incidence and valuation, for the final rulemaking.

This section explains what PM- and ozone-related health and environmental impacts EPA will quantify and monetize in the analysis for the final rules. EPA will base its analysis on peer-reviewed studies of air quality and health and welfare effects and peer-reviewed studies of the monetary values of public health and welfare improvements, and will be consistent with benefits analyses performed for the recent analysis of the proposed Ozone NAAQS and the final PM NAAQS analysis.[513] [514] These methods will be described in detail in the DRIA prepared for the final rule.

Though EPA is characterizing the changes in emissions associated with toxic pollutants, we will not be able to

[512] EPA notes, however, that the Ninth Circuit recently rejected an approach of assigning no monetized value to greenhouse gas reductions resulting from vehicular fuel economy. *Center for Biodiversity* v. *NHTSA,* F. 3d, (9th Cir. 2007).

[513] U.S. Environmental Protection Agency. July 2007. Regulatory Impact Analysis of the Proposed Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone. Prepared by: Office of Air and Radiation. EPA–452/R–07–008.

[514] U.S. Environmental Protection Agency. October 2006. Final Regulatory Impact Analysis (RIA) for the Proposed National Ambient Air Quality Standards for Particulate Matter. Prepared by: Office of Air and Radiation.

quantify or monetize the human health effects associated with air toxic pollutants for either the proposal or the final rule analyses. This is primarily because available tools and methods to assess air toxics risk from mobile sources at the national scale are not adequate for extrapolation to benefits assessment. In addition to inherent limitations in the tools for national-scale modeling of air quality and exposure, there is a lack of epidemiology data for air toxics in the general population. For a more comprehensive discussion of these limitations, please refer to the final Mobile Source Air Toxics rule.[515] Please refer to Section VII for more information about the air toxics emissions impacts associated with the proposed standard.

1. Human Health and Environmental Impacts

To model the ozone and PM air quality benefits of the final rules, EPA will use the Community Multiscale Air Quality (CMAQ) model (see Section VII.D.2 for a description of the CMAQ model). The modeled ambient air quality data will serve as an input to the Environmental Benefits Mapping and Analysis Program (BenMAP).[516] BenMAP is a computer program developed by EPA that integrates a number of the modeling elements used in previous DRIAs (e.g., interpolation functions, population projections, health impact functions, valuation functions, analysis and pooling methods) to translate modeled air concentration estimates into health effects incidence estimates and monetized benefits estimates.

Table IX.D.1–1 lists the co-pollutant health effect exposure-response functions ($PM_{2.5}$ and ozone) we will use to quantify the co-pollutant incidence impacts associated with the proposal.

TABLE IX.D.1–1—HEALTH IMPACT FUNCTIONS USED IN BENMAP TO ESTIMATE IMPACTS OF $PM_{2.5}$ AND OZONE REDUCTIONS

Endpoint	Pollutant	Study	Study population
Premature Mortality:			
Premature mortality—daily time series	O3	Multi-city	All ages.
		Bell et al. (2004)—Non-accidental	
		Huang et al. (2005)—Cardiopulmonary.	
		Schwartz (2005)—Non-accidental.	
		Meta-analyses:	
		Bell et al. (2005)—All cause.	
		Ito et al. (2005)—Non-accidental.	
		Levy et al. (2005)—All cause.	
Premature mortality—cohort study, all-cause	$PM_{2.5}$	Pope et al. (2002)	>29 years.
		Laden et al. (2006)	>25 years.
Premature mortality, total exposures	$PM_{2.5}$	Expert Elicitation (IEc, 2006)	>24 years.
Premature mortality—all-cause	$PM_{2.5}$	Woodruff et al. (1997)	Infant (<1 year).
Chronic Illness:			
Chronic Bronchitis	$PM_{2.5}$	Abbey et al. (1995)	>26 years.
Nonfatal heart attacks	$PM_{2.5}$	Peters et al. (2001)	Adults (>18 years).
Hospital Admissions:			
Respiratory	O3	Pooled estimate	>64 years.
		Schwartz (1995)—ICD 460–519 (all resp).	
		Schwartz (1994a; 1994b)—ICD 480–486 (pneumonia).	
		Moolgavkar et al. (1997)—ICD 480–487 (pneumonia).	
		Schwartz (1994b)—ICD 491–492, 494–496 (COPD).	
		Moolgavkar et al. (1997)—ICD 490–496 (COPD).	
		Burnett et al. (2001)	<2 years.
	$PM_{2.5}$	Pooled estimate	>64 years.
		Moolgavkar (2003)—ICD 490–496 (COPD).	
		Ito (2003)—ICD 490–496 (COPD).	
	$PM_{2.5}$	Moolgavkar (2000)—ICD 490–496 (COPD)	20–64 years.
	$PM_{2.5}$	Ito (2003)—ICD 480–486 (pneumonia)	>64 years.
	$PM_{2.5}$	Sheppard (2003)—ICD 493 (asthma)	<65 years.
Cardiovascular	$PM_{2.5}$	Pooled estimate	>64 years.
		Moolgavkar (2003)—ICD 390–429 (all Cardiovascular).	
		Ito (2003)—ICD 410–414, 427–428 (ischemic heart disease, dysrhythmia, heart failure).	
	$PM_{2.5}$	Moolgavkar (2000)—ICD 390–429 (all Cardiovascular).	20–64 years.
Asthma-related ER visits	O3	Pooled estimate	5–34 years.
		Jaffe et al. (2003)	All ages.
		Peel et al. (2005)	All ages.
		Wilson et al. (2005).	
	$PM_{2.5}$	Norris et al. (1999)	0–18 years.
Other Health Endpoints:			

[515] U.S. Environmental Protection Agency. February 2007. Control of Hazardous Air Pollutants from Mobile Sources: Final Regulatory Impact Analysis. Office of Air and Radiation. Office of Transportation and Air Quality. EPA420–R–07–002.

[516] Information on BenMAP, including downloads of the software, can be found at *http://www.epa.gov/ttn/ecas/benmodels.html*.

TABLE IX.D.1–1—HEALTH IMPACT FUNCTIONS USED IN BENMAP TO ESTIMATE IMPACTS OF $PM_{2.5}$ AND OZONE REDUCTIONS—Continued

Endpoint	Pollutant	Study	Study population
Acute bronchitis	$PM_{2.5}$	Dockery et al. (1996)	8–12 years.
Upper respiratory symptoms	$PM_{2.5}$	Pope et al. (1991)	Asthmatics, 9–11 years.
Lower respiratory symptoms	$PM_{2.5}$	Schwartz and Neas (2000)	7–14 years.
Asthma exacerbations	$PM_{2.5}$	Pooled estimate	6–18 years.
		Ostro et al. (2001) (cough, wheeze and shortness of breath).	
		Vedal et al. (1998) (cough).	
Work loss days	$PM_{2.5}$	Ostro (1987)	18–65 years.
School absence days	O3	Pooled estimate	5–17 years.
		Gilliland et al. (2001).	
		Chen et al. (2000).	
Minor Restricted Activity Days (MRADs)	O3	Ostro and Rothschild (1989)	18–65 years.
	$PM_{2.5}$	Ostro and Rothschild (1989)	18–65 years.

2. Monetized Impacts

Table IX.D.2–1 presents the monetary values we will apply to changes in the incidence of health and welfare effects associated with the RFS2 standard.

TABLE IX.D.2–1—VALUATION METRICS USED IN BENMAP TO ESTIMATE MONETARY BENEFITS

Endpoint	Valuation method	Valuation (2000$)
Premature mortality	Assumed Mean VSL	$5,500,000
Chronic Illness		
Chronic Bronchitis	WTP: Average Severity	340,482
Myocardial Infarctions, Nonfatal	Medical Costs Over 5 Years. Varies by age and discount rate. Russell (1998)	
	Medical Costs Over 5 Years. Varies by age and discount rate. Wittels (1990)	
Hospital Admissions		
Respiratory, Age 65+	COI: Medical Costs + Wage Lost	18,353
Respiratory, Ages 0–2	COI: Medical Costs	7,741
Chronic Lung Disease (less Asthma).	COI: Medical Costs + Wage Lost	12,378
Pneumonia	COI: Medical Costs + Wage Lost	14,693
Asthma	COI: Medical Costs + Wage Lost	6,634
Cardiovascular	COI: Medical Costs + Wage Lost (20–64)	22,778
	COI: Medical Costs + Wage Lost (65–99)	21,191
ER Visits, Asthma	COI: Smith et al. (1997)	312
	COI: Standford et al. (1999)	261
Other Health Endpoints		
Acute Bronchitis	WTP: 6 Day Illness, CV Studies	356
Upper Respiratory Symptoms	WTP: 1 Day, CV Studies	25
Lower Respiratory Symptoms	WTP: 1 Day, CV Studies	16
Asthma Exacerbation	WTP: Bad Asthma Day, Rowe and Chestnut (1986)	43
Work Loss Days	Median Daily Wage, County-Specific	
Minor Restricted Activity Days	WTP: 1 Day, CV Studies	51
School Absence Days	Median Daily Wage, Women 25+	75
Worker Productivity	Median Daily Wage, Outdoor Workers, County-Specific, Crocker and Horst (1981).	
Environmental Endpoints Recreational Visibility.	WTP: 86 Class I Areas	

Source: Dollar amounts for each valuation method were extracted from BenMAP version 2.4.5.

3. Other Unquantified Health and Environmental Impacts

In addition to the co-pollutant health and environmental impacts we will quantify for the analysis of the RFS2 standard, there are a number of other health and human welfare endpoints that we will not be able to quantify because of current limitations in the methods or available data. These impacts are associated with emissions of air toxics (including benzene, 1,3-butadiene, formaldehyde, acetaldehyde, acrolein, and ethanol), ambient ozone, and ambient $PM_{2.5}$ exposures. For example, we have not quantified a number of known or suspected health effects linked with ozone and PM for which appropriate health impact functions are not available or which do not provide easily interpretable outcomes (i.e., changes in heart rate variability). Additionally, we are currently unable to quantify a number of known welfare effects, including reduced acid and particulate deposition damage to cultural monuments and other materials, and environmental benefits due to reductions of impacts of eutrophication in coastal areas. For air toxics, the available tools and methods to assess risk from mobile sources at the national scale are not adequate for extrapolation to benefits assessment. In addition to inherent limitations in the tools for national-scale modeling of air toxics and exposure, there is a lack of epidemiology data for air toxics in the general population. Table IX.D.3–1 lists these unquantified health and environmental impacts.

TABLE IX.D.3–1—UNQUANTIFIED AND NON-MONETIZED POTENTIAL EFFECTS

Pollutant/Effects	Effects not included in analysis—changes in:
Ozone Health [a]	Chronic respiratory damage. Premature aging of the lungs. Non-asthma respiratory emergency room visits. Exposure to UVb (±) [d].
Ozone Welfare	Yields for: —commercial forests. —some fruits and vegetables. —non-commercial crops. Damage to urban ornamental plants. Impacts on recreational demand from damaged forest aesthetics. Ecosystem functions. Exposure to UVb (±).
PM Health [b]	Premature mortality—short term exposures.[c] Low birth weight. Pulmonary function. Chronic respiratory diseases other than chronic bronchitis. Non-asthma respiratory emergency room visits. Exposure to UVb (±).
PM Welfare	Residential and recreational visibility in non-Class I areas. Soiling and materials damage. Damage to ecosystem functions. Exposure to UVb (±).
Nitrogen and Sulfate Deposition Welfare.	Commercial forests due to acidic sulfate and nitrate deposition. Commercial freshwater fishing due to acidic deposition. Recreation in terrestrial ecosystems due to acidic deposition. Existence values for currently healthy ecosystems. Commercial fishing, agriculture, and forests due to nitrogen deposition. Recreation in estuarine ecosystems due to nitrogen deposition. Ecosystem functions. Passive fertilization.
CO Health	Behavioral effects.
Hydrocarbon (HC)/Toxics Health [e].	Cancer (benzene, 1,3-butadiene, formaldehyde, acetaldehyde, ethanol). Anemia (benzene). Disruption of production of blood components (benzene). Reduction in the number of blood platelets (benzene). Excessive bone marrow formation (benzene). Depression of lymphocyte counts (benzene). Reproductive and developmental effects (1,3-butadiene, ethanol). Irritation of eyes and mucus membranes (formaldehyde). Respiratory irritation (formaldehyde). Asthma attacks in asthmatics (formaldehyde). Asthma-like symptoms in non-asthmatics (formaldehyde). Irritation of the eyes, skin, and respiratory tract (acetaldehyde). Upper respiratory tract irritation and congestion (acrolein).
HC/Toxics Welfare [f].	Direct toxic effects to animals. Bioaccumulation in the food chain. Damage to ecosystem function. Odor.

[a] In addition to primary economic endpoints, there are a number of biological responses that have been associated with ozone health effects including increased airway responsiveness to stimuli, inflammation in the lung, acute inflammation and respiratory cell damage, and increased susceptibility to respiratory infection. The public health impact of these biological responses may be partly represented by our quantified endpoints.

[b] In addition to primary economic endpoints, there are a number of biological responses that have been associated with PM health effects including morphological changes and altered host defense mechanisms. The public health impact of these biological responses may be partly represented by our quantified endpoints.

[c] While some of the effects of short-term exposures are likely to be captured in the estimates, there may be premature mortality due to short-term exposure to PM not captured in the cohort studies used in this analysis. However, the PM mortality results derived from the expert elicitation do take into account premature mortality effects of short term exposures.

[d] May result in benefits or disbenefits.

[e] Many of the key hydrocarbons related to this rule are also hazardous air pollutants listed in the Clean Air Act. Please refer to Section VII.E.4 for additional information on the health effects of air toxics.

[f] Please refer to Section VII.E for additional information on the welfare effects of air toxics.

While there will be impacts associated with air toxic pollutant emission changes that result from the RFS2 standard, we will not attempt to monetize those impacts. This is primarily because currently available tools and methods to assess air toxics risk from mobile sources at the national scale are not adequate for extrapolation to incidence estimations or benefits assessment. The best suite of tools and methods currently available for assessment at the national scale are those used in the National-Scale Air Toxics Assessment (NATA). The EPA Science Advisory Board specifically commented in their review of the 1996 NATA that these tools were not yet ready for use in a national-scale benefits analysis, because they did not consider the full distribution of exposure and risk, or address sub-chronic health effects.[517] While EPA has since improved the tools, there remain critical limitations for estimating incidence and assessing benefits of reducing mobile source air toxics. EPA continues to work to address these limitations; however, we do not anticipate having methods and tools available for national-scale application in time for the analysis of the final rules. Please refer to the final Mobile Source Air Toxics Rule RIA for more discussion.[518]

E. Economy-Wide Impacts

It is anticipated that this proposed rulemaking will have impacts on the U.S. economy that extend beyond the two sectors most directly affected—the transportation and agriculture sectors. Consider how the proposed rulemaking will affect the overall U.S. economy. By requiring 36 billion gallons of renewable transportation fuels in the U.S. transportation sector by 2022, it is anticipated that the cost of motor vehicle fuels will increase. This cost increase will impact all sectors of the economy that use motor vehicles fuels, as intermediate inputs to production. For example, manufacturing firms will see an increase in their shipping costs. Households will also be impacted as consumers of these goods, and directly as consumers of motor vehicle fuels. Additionally, it is anticipated that the production of renewable fuels will increase the demand for U.S. farm

[517] Science Advisory Board. 2001. NATA—Evaluating the National-Scale Air Toxics Assessment for 1996—an SAB Advisory. *http://www.epa.gov/ttn/atw/sab/sabrev.html.*

[518] U.S. EPA. 2007. Control of Hazardous Air Pollutants From Mobile Sources—Regulatory Impact Analysis. Assessment and Standards Division. Office of Transportation and Air Quality. EPA420R–07–002. February.

products, and increase farm incomes. This will have ripple effects for sectors that supply inputs to the U.S. farm sector (e.g. tractors), and sectors that demand outputs from the farm sector. The sum of all of these impacts will affect the total levels of output and consumption in the U.S. economy. Because multiple markets beyond the transportation sector will be affected by the proposed rulemaking, a general equilibrium analysis is required to provide a more accurate picture of the social cost of the policy than a partial equilibrium analysis. (A partial equilibrium analysis looks at the impacts in one market of the economy but does not attempt to capture the full interaction of a policy change in all markets simultaneously, as a general equilibrium model does).

In order to estimate the impacts of the RFS2 rule on U.S. gross domestic product (GDP) and consumption, EPA intends to use an economy-wide, computable general equilibrium (CGE) model between proposal and the final rule. This model will use detailed fuel sector cost estimates provided in Section VIII as inputs to determine the economy-wide impacts of the rulemaking. The economy-wide model to be utilized for this analysis is the Intertemporal General Equilibrium Model (IGEM). IGEM is a model of the U.S. economy with an emphasis on the energy and environmental aspects. It is a dynamic model, which depicts growth of the economy due to capital accumulation, technical change and population change. It is a detailed multi-sector model covering thirty-five industries of the U.S. economy. It also depicts changes in consumption patterns due to demographic changes, price and income effects. The substitution possibilities for both producers and consumers in IGEM are driven by model parameters that are based on observed market behavior revealed over the past forty to fifty years. EPA seeks comment on the modeling approach to be utilized to estimate the economy-wide impacts of the RFS2 proposal.

An additional issue that arises is how biofuel subsidies are considered from an economy-wide perspective. The Renewable Fuels Standard, by encouraging the use of biofuels, will result in an expansion of subsidy payments by the U.S. For example, each gallon of corn-based ethanol sold in the U.S. qualifies for a $0.45/gallon subsidy. One assumption that could be made is that biofuel subsidies, which are a loss in revenue to the U.S. government, are offset by an increase in taxes by the U.S. In this case, the Renewable Fuels Standard program becomes revenue neutral. If taxes are raised to offset the revenue loss from the subsidies, the taxes could have a distortionary impact on the economy. For example, if taxes are raised on labor and capital, then there will less output. To account for the potential distortionary impacts of increased taxes, as a rule of thumb, it is sometimes assumed that for each dollar of tax revenue raised, there is a $0.25 loss in output in the economy. We intend to consider the impact of the expansion of biofuel subsidies from the RFS2 in the context of the economy-wide modeling.

X. Impacts on Water

A. Background

As the production and price of corn and other biofuel feedstocks increase, there may be substantial impacts to both water quality and water quantity. To analyze the potential water-related impacts, EPA focused on agricultural corn production for several reasons. Corn acres have increased dramatically, 20% in 2007. Although corn acres declined seven percent in 2008, total corn acres remained the second highest since 1946.[519] Corn has the highest fertilizer and pesticide use per acre and accounts for the largest share of nitrogen fertilizer use among all crops.[520] Corn generally utilizes only 40 to 60% of the applied nitrogen fertilizer. The remaining nitrogen is available to leave the field and runoff to surface waters, leach into ground water, or volatilize to the air where it can return to water through depositional processes.

There are three major pathways for contaminants to reach water from agricultural lands: run off from the land's surface, subsurface tile drains, or leaching to ground water. A variety of management factors influence the potential for contaminants such as fertilizers, sediment, and pesticides to reach water from agricultural lands. These factors include nutrient and pesticide application rates and application methods, use of conservation practices and crop rotations by farmers, and acreage and intensity of tile drained lands.

Historically, corn has been grown in rotation with other crops, especially soybeans. As corn prices increase relative to prices for other crops, more farmers are choosing to grow corn every year (continuous corn). Continuous corn production results in significantly greater nitrogen losses annually than a corn-soybean rotation and lower yields per acre. In response, farmers may add higher rates of nitrogen fertilizer to try to match yields of corn grown in rotation. Growing continuous corn also increases the viability of pests such as corn rootworm. Farmers may increase use of pesticides to control these pests. As corn acres increase, use of the common herbicides like atrazine and glyphosate (e.g. Roundup) may also increase.

High corn prices may encourage farmers to grow corn on lands that are marginal for row production such as hay land or pasture. Typically, agricultural producers apply far less fertilizer and pesticide on pasture land than land in row crops. Corn yield on these marginal lands will be lower and may require higher fertilizer rates. However since nitrogen fertilizer prices are tied to oil prices, fertilizer costs have increased significantly recently. It is unclear how agricultural producers have responded to these increases in both corn and fertilizer prices. EPA solicits comments on the impact of corn and fertilizer prices on nitrogen fertilizer use.

Tile drainage is another important factor in determining the losses of fertilizer from cropland. Tile drainage consists of subsurface tiles or pipes that move water from wet soils to surface waters quickly so crops can be planted. Tile drainage has transformed large expanses of historic wetland soils into productive agriculture lands. However, the tile drains also move fertilizers and pesticides more quickly to surface waters without any of the attenuation that would occur if these contaminants moved through soils or wetlands. The highest proportion of tile drainage occurs in the Upper Mississippi and the Ohio-Tennessee River basins.[521]

The increase in corn production and prices may also have significant impacts on voluntary conservation programs funded by the U.S. Department of Agriculture (USDA) that are important to protect water quality. As land values increase due to higher crop prices, USDA payments may not keep up with the need for farmers and tenant farmers, to make an adequate return. For example, farmland in Iowa increased an

[519] U.S. Department of Agriculture, National Agricultural Statistics Service, "Acreage", 2008, available online at: *http://usda.mannlib.cornell.edu/usda/current/Acre/Acre-06–30–2008.pdf.*

[520] Committee on Water Implications of Biofuels Production in the United States, National Research Council, 2008, Water implications of biofuels production in the United States, The National Academies Press, Washington, DC, 88 p.

[521] U.S. Environmental Protection Agency, EPA Science Advisory Board, Hypoxia in the northern Gulf of Mexico, EPA–SAB–08–003, 275 p, available online at: *http://yosemite.epa.gov/sab/sabproduct.nsf/C3D2F27094E03F90852573B800601D93/$File/EPA–SAB–08–003complete.unsigned.pdf.*

average of 18% in 2007 from 2006 prices.

Both land retirement programs like the Conservation Reserve Program (CRP) and working land programs like the Environmental Quality Incentives Program (EQIP) can be affected. Under CRP, USDA contracts with farmers to take land out of agricultural production and plant grasses or trees. Generally farmers put land into CRP because it is not as productive and has other characteristics that make the cropland more environmentally sensitive, such as high erosion rates. CRP provides valuable environmental benefits both for water quality and for wildlife habitat. Midwestern states, where much of U.S. corn is grown, tend to have lower CRP reenrollment rates than the national average. Under EQIP, USDA makes cost-share payments to farmers to implement conservation practices. Some of the most cost-effective practices include: Riparian buffers; crop rotation; appropriate rate, timing, and method of fertilizer application; cover crops; and, on tile-drained lands, treatment wetlands and controlled drainage. Producers may be less willing to participate and require higher payments to offset perceived loss of profits through implementation of conservation practices.

1. Ecological Impacts

Nitrogen and phosphorus enrichment due to human activities is one of the leading problems facing our nation's lakes, reservoirs, and estuaries. Nutrient enrichment also has negative impacts on aquatic life in streams; adverse health effects on humans and domestic animals; and impairs aesthetic and recreational use. Excess nutrients can lead to excessive growth of algae in rivers and streams, and aquatic plants in all waters. For example, declines in invertebrate community structure have been correlated directly with increases in phosphorus concentration. High concentrations of nitrogen in the form of ammonia are known to be toxic to aquatic animals. Excessive levels of algae have also been shown to be damaging to invertebrates. Finally, fish and invertebrates will experience growth problems and can even die if either oxygen is depleted or pH increases are severe; both of these conditions are symptomatic of eutrophication. As a biologic system becomes more enriched by nutrients, different species of algae may spread and species composition can shift.

Nutrient pollution is widespread. The most widely known examples of significant nutrient impacts include the Gulf of Mexico and the Chesapeake Bay. There are also known impacts in over 80 estuaries/bays, and thousands of rivers, streams, and lakes. Waterbodies in virtually every state and territory in the U.S. are impacted by nutrient-related degradation. Reducing nutrient pollution is a priority for EPA. The combustion of transportation fuels results in significant loadings of nitrogen from air deposition to waterbodies around the country, including the Chesapeake Bay, Long Island Sound, and Lake Tahoe.

2. Gulf of Mexico

Production of corn for ethanol may exacerbate existing serious water quality problems in the Gulf of Mexico. Nitrogen fertilizer applications to corn are already the major source of total nitrogen loadings to the Mississippi River. A large area of low oxygen, or hypoxia, forms in the Gulf of Mexico every year, often called the ''dead zone.'' The primary cause of the hypoxia is excess nutrients (nitrogen and phosphorus) from the Upper Midwest flowing into the Mississippi River to the Gulf. These nutrients trigger excessive algal growth (or eutrophication) resulting in reduced sunlight, loss of aquatic habitat, and a decrease in oxygen dissolved in the water. Hypoxia threatens commercial and recreational fisheries in the Gulf because fish and other aquatic species cannot live in the low oxygen waters.

In 2008, the hypoxic zone was the second largest since measurements began in 1985—8,000 square miles, an area larger than the state of Massachusetts, and slightly larger than the 2007 measurement.[522] The Mississippi River/Gulf of Mexico Watershed Nutrient Task Force's ''Gulf Hypoxia Action Plan 2008'' calls for a 45% reduction in both nitrogen and phosphorus reaching the Gulf to reduce the size of the zone.[523] An additional reduction in nitrogen and phosphorus reduction would be necessary as a result of increased corn production for ethanol and climate change impacts.

Alexander, et al.[524] modeled the sources of nutrient loadings to the Gulf of Mexico using the USGS SPARROW model. They estimated that agricultural sources contribute more than 70% of the delivered nitrogen and phosphorus. Corn and soybean production accounted for 52% of nitrogen delivery and 25% of the phosphorus.

Several recent scientific reports have estimated the impact of increasing corn acres for ethanol in the Gulf of Mexico watershed. Donner and Kucharik's[525] study showed increases in nitrogen export to the Gulf as a result of increasing corn ethanol production from 2007 levels to 15 billion gallons in 2022. They concluded that the expansion of corn-based ethanol production could make it almost impossible to meet the Gulf of Mexico nitrogen reduction goals without a ''radical shift'' in feed production, livestock diet, and management of agricultural lands. The study estimated a mean dissolved inorganic nitrogen load increase of 10 to 18% from 2007 to 2022 to meet the 15 billion gallon corn ethanol goal. EPA's Science Advisory Board report to the Mississippi River/Gulf of Mexico Watershed Task Force estimated that corn grown for ethanol will result in an additional national annual loading of almost 300 million pounds of nitrogen. An estimated 80% of that nitrogen loading or 238 million pounds will occur in the Mississippi-Atchafalaya River basin and contribute nitrogen to the hypoxia in the Gulf of Mexico.[526]

B. Upper Mississippi River Basin Analysis

To provide a quantitative estimate of the impact of this proposal and production of corn ethanol generally on water quality, EPA conducted an analysis that modeled the changes in loadings of nitrogen, phosphorus, and sediment from agricultural production in the Upper Mississippi River Basin (UMRB). The UMRB drains approximately 189,000 square miles, including large parts of the states of Illinois, Iowa, Minnesota, Missouri, and Wisconsin. Small portions of Indiana, Michigan, and South Dakota are also within the basin. EPA selected the UMRB because it is representative of the many potential issues associated with ethanol production, including its connection to major water quality

[522] Louisiana Universities Marine Consortium, 2008, 'Dead zone' again rivals record size, available online at: *http://www.gulfhypoxia.net/research/shelfwidecruises/2008/PressRelease08.pdf.*

[523] Mississippi River/Gulf of Mexico Watershed Nutrient Task Force, 2008, Gulf hypoxia action plan 2008 for reducing, mitigating, and controlling hypoxia in the northern Gulf of Mexico and improving water quality in the Mississippi River basin, 61 p., Washington, DC, available online at: *http://www.epa.gov/msbasin/actionplan.htm.*

[524] Alexander, R.B., Smith, R.A., Schwarz, G.E., Boyer, E.W., Nolan, J.V., and Brakebill, J.W., 2008, Differences in phosphorus and nitrogen delivery to the Gulf of Mexico from the Mississippi River basin, Environmental Science and Technology, v. 42, no. 3, p. 822–830, available online at: *http://pubs.acs.org/cgi-bin/abstract.cgi/esthag/2008/42/i03/abs/es0716103.html.*

[525] Donner, S. D. and Kucharik, C. J., 2008, Corn-based ethanol production compromises goal of reducing nitrogen export by the Mississippi River, PNAS, v. 105, no. 11, p. 4513–4518, available online at: *http://www.pnas.org/content/105/11/4513.full.*

[526] U.S. EPA, supra note 4.

concerns such as Gulf of Mexico hypoxia, large corn production, and numerous ethanol production plants. For more details on the analysis, see Chapter 6 in the DRIA.

On average the UMRB contributes about 39% of the total nitrogen loads and 26% of the total phosphorus loads to the Gulf of Mexico.[527] The high percentage of nitrogen from the UMRB is primarily due to the large inputs of fertilizer for agriculture and the 60% of cropland that is tile drained. Although nitrogen inputs to the UMRB in recent years is fairly level, there is a 21% decline in net inputs from humans. The Science Advisory Board report attributes this decline to higher amount of nitrogen removed during harvest, due to higher crop yields. For the same time period, phosphorus inputs increased 12%.

1. SWAT Model

EPA selected the SWAT (Soil and Water Assessment Tool) model to assess nutrient loads from changes in agricultural production in the UMRB. Models are the primary tool that can be used to predict future impacts based on alternative scenarios. SWAT is a physical process model developed to quantify the impact of land management practices in large, complex watersheds.[528]

2. Baseline Model Scenario

In order to assess alternative potential future conditions within the UMRB, EPA developed a SWAT model of a Baseline Scenario against which to analyze the impact of increased corn production for biofuel. For simplicity's sake, we refer to the baseline as 2005, but like most water quality modeling, we had to use a range of data sets for the inputs. As noted above corn acres did not increase significantly until the 2007 crop year. While this baseline does not directly quantify the impacts of this proposal on water quality, it is useful in understanding the magnitude of the impacts of corn production for biofuels. EPA plans to conduct additional analyses for the final rule that will compare the reference case biofuel volumes to the RFS2 volumes.

The SWAT model was applied (i.e., calibrated) to the UMRB using 1960 to 2001 weather data and flow and water quality data from 13 USGS gages on the mainstem of the Mississippi River. The 42-year SWAT model runs were performed and the results analyzed to establish runoff, sediment, nitrogen, and phosphorous loadings from each of the 131 8-digit HUC subwatersheds and the larger 4-digit subbasins, along with the total outflow from the UMRB and at the various USGS gage sites along the Mississippi River. These results provided the Baseline Scenario model values to which the future alternatives are compared.

3. Alternative Scenarios

SWAT scenario analyses were performed for the years 2010, 2015, 2020, and 2022 with corn ethanol volumes of 12 billion gallons a year (BGY) for 2010, and 15 BGY for 2015 to 2022. These volumes were adjusted for the UMRB based on a 42.3% ratio of ethanol production capacity within the UMRB compared to national capacity. The resulting UMRB ethanol production goals were converted into the corresponding required corn production acreage, i.e. the extent of corn acreage needed to meet those ethanol production goals. Annual increases in corn yield of 1.23% were built into the future scenarios. Fewer corn acres were needed to meet ethanol production goals after the 2015 scenario due to those yield increases.

Table X.B.3–1 and Table X.B.3–2 summarize the model outputs both within the UMRB and at the outlet of the UMRB in the Mississippi River at Grafton, Illinois for each of the four scenario years: 2010, 2015, 2020, and 2022. It is important to note that these results only estimate loadings from the Upper Mississippi River basin, not the entire Mississippi River watershed. As noted earlier, the UMRB contributes about 39% of the total nitrogen loads and 26% of total phosphorus loads to the Gulf of Mexico. Due to the timing of this proposal, we were not able to assess the local impact in smaller watersheds within the UMRB. Those impacts may be significantly different. The decreasing nitrogen load over time is likely attributed to the increased corn yield production, resulting in greater plant uptake of nitrogen.

TABLE X.B.3–1—CHANGES IN NUTRIENT LOADINGS WITHIN THE UPPER MISSISSIPPI RIVER BASIN FROM THE 2005 BASELINE SCENARIO

	2005 Baseline	2010	2015	2020	2022
Nitrogen	1897.0 million lbs	+5.1%	+4.2%	+2.2%	+1.6%
Phosphorus	176.6 million lbs	+2.3%	+1.1%	+0.6%	+0.4%

About 24% of nitrogen and 25% of phosphorus leaving agricultural fields was assimilated (taken by aquatic plants or volatilized) before reaching the outlet of the UMRB. The assimilated nitrogen is not necessarily eliminated as an environmental concern. Five percent or more of the nitrogen can be converted to nitrous gas, a powerful greenhouse gas that has 300 times the climate-warming potential of carbon dioxide, the major greenhouse. Thus, a water pollutant becomes an air pollutant until it is either captured through biological sequestration or converted fully to elemental nitrogen.

Total sediment outflow showed very little change over all scenarios. This is likely due to the corn being modeled as well-managed crop in terms of sediment loss, primarily due to the corn stover remaining on the fields following harvest.

TABLE X.B.3–2—CHANGES FROM THE 2005 BASELINE TO THE MISSISSIPPI RIVER AT GRAFTON, ILLINOIS FROM THE UPPER MISSISSIPPI RIVER BASIN

	2005 Baseline	2010	2015	2020	2022
Average corn yield (bushels/acre)	141	150	158	168	171

[527] Mississippi River/Gulf of Mexico Watershed Nutrient Task Force, supra note 6.

[528] Gassman, P.W., Reyes, M.R., Green, C.H., Arnold, J.G., 2007, The soil and water assessment tool: Historical development, applications, and future research directions. Transactions of the American Society of Agricultural and Biological Engineers, v. 50, no. 4, p. 1211–1240. *http://www.card.iastate.edu/environment/items/asabe_swat.pdf.*

TABLE X.B.3–2—CHANGES FROM THE 2005 BASELINE TO THE MISSISSIPPI RIVER AT GRAFTON, ILLINOIS FROM THE UPPER MISSISSIPPI RIVER BASIN—Continued

	2005 Baseline	2010	2015	2020	2022
Nitrogen	1,433.5 million lbs	+5.5%	+4.7%	+2.5%	+1.8%
Phosphorus	132.4 million lbs	+2.8%	+1.7%	+0.98%	+0.8%
Sediment	6.4 million tons	+0.5%	+0.3%	+0.2%	+0.1%

After evaluating comments on this proposal, if time and resources permit, EPA may conduct additional water quality analyses using the SWAT model in the UMRB. Potential future analyses could include: (1) Determination of the most sensitive assumptions in the model, (2) water quality impacts from the changes in ethanol volumes between the reference case and this proposal, (3) removing corn stover for cellulosic ethanol, and (4) a case study of a smaller watershed to evaluate local water quality impacts that are impossible to ascertain at the scale of the UMRB.

EPA solicits comments on the scenarios developed for this proposal and additional future analyses. At this time, we are not able to assess the impact of these additional loadings on the size of the Gulf of Mexico hypoxia zone or water quality within the UMRB. EPA also solicits comments on the significance of the modeled increases in nitrogen and phosphorus loads.

C. Additional Water Issues

Water quality and quantity impacts resulting from corn ethanol production go beyond our ability to model. The following issues are summarized to provide additional context about the broader range of potential impacts. *See* Chapter 6 in the DRIA for more discussion of these issues.

1. Chesapeake Bay Watershed

Agricultural lands contribute more nutrients to the Chesapeake Bay than any other land use. Chesapeake Bay Program partners have pledged to significantly reduce nutrients to the Bay to meet water quality goals. To estimate the increase in nutrient loads to the Bay from changes to agricultural crop production from 2005 to 2008, the Chesapeake Bay Program Watershed Model Phase 4.3 and Vortex models were utilized. Total nitrogen loads increased by almost 2.4 million pounds from an increase of almost 66,000 corn acres. As agriculture land use shifts from hay and pasture to more intensively fertilized row crops, this analysis estimates that nitrogen loads increase by 8.8 million pounds.

2. Ethanol Production

There are three principal sources of discharges to water from ethanol plants: Reject water from water purification, cooling water blowdown, and off-batch ethanol. Most ethanol facilities use on-site wells to produce the process water for the ethanol process. Groundwater sources are generally not suitable for process water because of their mineral content. Therefore, the water must be treated, commonly by reverse osmosis. For every two gallons of pure water produced, about a gallon of brine is discharged as reject water from this process. Most estimates of water consumption in ethanol production are based on the use of clean process water and neglect the water discharged as reject water.

The largest source of wastewater discharge is reverse osmosis reject water from process water purification. The reverse osmosis process concentrates groundwater minerals to levels where they can have water quality impacts. There is really no means of ''treating'' these ions to reduce toxicity, other than further concentration and disposal, or use of instream dilution. Some facilities have had to construct long pipelines to get access to dilution so they can meet water quality standards. Ethanol plants also discharge cooling water blowdown, where some water is discharged to avoid the buildup of minerals in the cooling system. These brines are similar to the reject water described above. In addition, if off-batch ethanol product or process water is discharged, the waste stream can have high Biochemical Oxygen Demand (BOD) levels. BOD directly affects the amount of dissolved oxygen in rivers and streams. The greater the BOD, the more rapidly oxygen is depleted in the stream. The consequences of high BOD are the same as those for low dissolved oxygen: Aquatic organisms become stressed, suffocate, and die.

Older generation production facilities used four to six gallons of process water to produce a gallon of ethanol, but newer facilities use less than three gallons of water in the production process. Most of this water savings is gained through improved recycling of water and heat in the process. Water supply is a local issue, and there have been concerns with water consumption as new plants go online. Some facilities are tapping into deeper aquifers as a source of water. These deeper water resources tend to contain higher levels of minerals and this can further increase the concentration of minerals in reverse osmosis reject water. Geographic impacts of water use vary. A typical plant producing 50 million gallons of ethanol per year uses a minimum of 175 million gallons of water annually. In Iowa, water consumption from ethanol refining accounts for about seven percent of all industrial water use, and is projected to be 14% by 2012—or about 50 million gallons per day.

a. Distillers Grain with Solubles

Distillers grain with solubles (DGS) is an important co-product of ethanol production. About one-third of the corn processed into ethanol is converted into DGS. DGS has become an increasingly important feed component for confined livestock. DGS are higher in crude protein (nitrogen) and three to four times higher in phosphorus relative to traditional feeds. When nitrogen and phosphorus are fed in excess of the animal's needs, these nutrients are excreted in the manure. When manure is applied to crops at rates above their nutrient needs or at times the crop can not use the nutrients, the nutrients can runoff to surface waters or leach into ground waters.

Livestock producers can limit the potential pollution from manure applications to crops by implementing comprehensive nutrient management. Due to the substantially higher phosphorus content of manure from livestock fed DGS, producers will potentially need significantly more acres to apply the manure so that phosphorus will not be applied at rates above the needs of the crops. This is a particularly important concern in areas where concentrated livestock production already produces more phosphorus in the manure than can be taken up by crops or pasture land in the vicinity.

Several recent studies have indicated that DGS may have an impact on food safety. Cattle fed DGS have a higher prevalence of a major food-borne pathogen, E. coli O157, than cattle without DGS in their diets.[529] More research is needed to confirm these studies and devise methods to eliminate the potential risks.

b. Ethanol Leaks and Spills

The potential for exposure to fuel components and/or additives can occur when underground fuel storage tanks leak fuel into ground water that is used for drinking water supplies or when spills occur that contaminate surface drinking water supplies. Ethanol biodegrades quickly and is not necessarily the pollutant of greatest concern in these occurrences. Instead, ethanol's high biodegradability can cause the plume of BTEX (benzene, toluene, ethylbenzene and xylenes) compounds in fuel to extend farther (by as much as 70%)[530] and persist longer in ground water, thereby increasing potential exposures to these compounds.

With the increasing use of ethanol in the fuel supply nationwide, it is important to understand the impact of ethanol on the existing tank infrastructure. Given the corrosivity of ethanol, there is concern regarding the increased potential for leaks from existing gas stations and subsequent impacts on drinking water supplies. In 2007, there were 7,500 reported releases from underground storage tanks. Therefore, EPA is undertaking analyses designed to assess the potential impacts of ethanol blends on tank infrastructure and leak detection systems and determine the resulting water quality impacts.

3. Biodiesel Plants

Biodiesel plants use much less water than ethanol plants. Water is used for washing impurities from the finished product. Water use is variable, but is usually less than one gallon of water for each gallon of biodiesel produced. Larger well-designed plants use water more sparingly, while smaller producers use more water. Some facilities recycle washwater, which reduces water consumption. The strength of process wastewater from biodiesel plants is highly variable. Most production processes produce washwater that has very high BOD levels. The high strength of these wastes can overload and disrupt municipal treatment plants.

Crude glycerin is an important side product from the biodiesel process and is about 10% of the final product. The rapid development of the biodiesel industry has caused a glut of glycerin production and many facilities dispose of glycerin. Poor handling of crude glycerin has resulted in upset of sewage treatment plants and fish kills.

4. Water Quantity

Water demand for crop production for ethanol could potentially be much larger than biorefinery demand. According to the National Research Council, the demand for water to irrigate crops for biofuels will not have an impact on national water use, but it is likely to have significant local and regional impacts.[531] The impact is crop and region specific, but could be especially great in areas where new acres are irrigated.

5. Drinking Water

Increased corn production for ethanol may increase the occurrence of nitrate, nitrite, and the herbicide atrazine in sources of drinking water. Under the Safe Drinking Water Act, EPA has established enforceable standards for these contaminants to protect public health. Increases in occurrence of these contaminants may raise costs to public water systems through increased treatment needs or increased pumping costs where ethanol production is accelerating the long running depletion of aquifers. There is also a risk of decreased supplies of drinking water in communities where aquifers are being depleted and potential contamination due to leaks from gasoline stations using higher blends of ethanol.

D. Request for Comment on Options for Reducing Water Quality Impacts

EPA is seeking comment on how best to reduce the impacts of biofuels on water quality. EPA is seeking comment on the use of section 211(c) of the Clean Air Act, as amended by EISA, to address these water quality issues. Section 211(c) gives the EPA administrator the discretion to ''control'' the manufacture and sale of a motor vehicle transportation fuel based on a finding that the fuel, or its emission product, ''causes or contributes'' to air pollution or water pollution that may reasonably be anticipated to endanger the public health or welfare.

In evaluating this option, EPA is seeking comment on whether it would be appropriate to find that emission products from such transportation fuels, including renewable fuels, are ''causing or contributing'' to ''water pollution'' and that this water pollution ''may reasonably be anticipated to endanger the public health or welfare.'' EPA is also seeking comment on whether it would be allowable and appropriate to ''control or prohibit the manufacture * * * '' of a fuel by requiring that manufacturers of such fuels, such as manufacturers of a biofuel, use, or certify that they used, only corn feedstocks grown using farming practices designed to reduce nutrient water pollution. For example, is this a reasonable way to ''offset'' water pollution caused, in part, by air deposition of nitrogen to water from combustion of transportation fuels with reductions of nitrogen runoff to water from corn feedstock by means of such ''controls'' on the manufacture of biofuels adopted pursuant to section 211(c). In the alternative, would this be a reasonable way to attempt to offset water pollution caused by the production of the feedstock associated with the production of the biofuel based on section 211(c).

EPA is seeking comment and suggestions on how biofuel manufacturers might establish that their biofuel feedstock was grown with appropriate practices to control nutrient runoff (e.g., require a program similar to the one used for compliance with the restrictions in the definition of renewable biomass on previously cleared agricultural land). Finally, EPA is seeking comments on other approaches, mechanisms, or authorities that might be adopted in the renewable fuels rule that are likely to have the effect of reducing the water quality impacts of biofuels.

XI. Public Participation

We request comment on all aspects of this proposal. This section describes how you can participate in this process.

A. How Do I Submit Comments?

We are opening a formal comment period by publishing this document. We will accept comments during the period indicated under **DATES** in the first part of this proposal. If you have an interest in the proposed program described in this document, we encourage you to comment on any aspect of this rulemaking. We also request comment on specific topics identified throughout this proposal.

Your comments will be most useful if you include appropriate and detailed

[529] Jacob, M. D., Fox, J. T., Drouillard, J. S., Renter, D. G., Nagaraja, T. G., 2008, Effects of dried distillers' grain on fecal prevalence and growth of *Escherichia coli* O157 in batch culture fermentations from cattle, Applied and Environmental Microbiology, v. 74, no. 1, p. 38–43, available online at: *http://aem.asm.org/cgi/content/abstract/74/1/38*

[530] Ruiz-Aguilar, G. M. L.; O'Reilly, K.; Alvarez, P. J. J., 2003, Forum: A comparison of benzene and toluene plume lengths for sites contaminated with regular vs. ethanol-amended gasoline, Ground Water Monitoring and Remediation, v. 23, p. 48–53.

[531] Committee on Water Implications of Biofuels Production in the United States, supra note 2.

supporting rationale, data, and analysis. Commenters are especially encouraged to provide specific suggestions for any changes to any aspect of the regulations that they believe need to be modified or improved. You should send all comments, except those containing proprietary information, to our Air Docket (*see* **ADDRESSES** in the first part of this proposal) before the end of the comment period.

You may submit comments electronically, by mail, or through hand delivery/courier. To ensure proper receipt by EPA, identify the appropriate docket identification number in the subject line on the first page of your comment. Please ensure that your comments are submitted within the specified comment period. Comments received after the close of the comment period will be marked ''late.'' EPA is not required to consider these late comments. If you wish to submit Confidential Business Information (CBI) or information that is otherwise protected by statute, please follow the instructions in Section XI.B.

B. How Should I Submit CBI to the Agency?

Do not submit information that you consider to be CBI electronically through the electronic public docket, www.regulations.gov, or by e-mail. Send or deliver information identified as CBI only to the following address: U.S. Environmental Protection Agency, Assessment and Standards Division, 2000 Traverwood Drive, Ann Arbor, MI, 48105, Attention Docket ID EPA–HQ–OAR–2005–0161. You may claim information that you submit to EPA as CBI by marking any part or all of that information as CBI (if you submit CBI on disk or CD–ROM, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is CBI). Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

In addition to one complete version of the comments that include any information claimed as CBI, a copy of the comments that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. If you submit the copy that does not contain CBI on disk orCD–ROM, mark the outside of the disk or CD–ROM clearly that it does not contain CBI. Information not marked as CBI will be included in the public docket without prior notice. If you have any questions about CBI or the procedures for claiming CBI, please consult the person identified in the **FOR FURTHER INFORMATION CONTACT** section.

C. Will There Be a Public Hearing?

We will hold a public hearing in Washington DC on June 9, 2009 at the location shown below. The hearing will start at 10 a.m. local time and continue until everyone has had a chance to speak.

The Dupont Hotel, 1500 New Hampshire Avenue, NW., Washington, DC 20036, Phone# 202–483–6000.

If you would like to present testimony at the public hearing, we ask that you notify the contact person listed under **FOR FURTHER INFORMATION CONTACT** in the first part of this proposal at least 8 days before the hearing. You should estimate the time you will need for your presentation and identify any needed audio/visual equipment. We suggest that you bring copies of your statement or other material for the EPA panel and the audience. It would also be helpful if you send us a copy of your statement or other materials before the hearing.

We will make a tentative schedule for the order of testimony based on the notifications we receive. This schedule will be available on the morning of the hearing. In addition, we will reserve a block of time for anyone else in the audience who wants to give testimony.

We will conduct the hearing informally, and technical rules of evidence will not apply. We will arrange for a written transcript of the hearing and keep the official record of the hearing open for 30 days to allow you to submit supplementary information. You may make arrangements for copies of the transcript directly with the court reporter.

D. Comment Period

The comment period for this rule will end on July 27, 2009.

E. What Should I Consider as I Prepare My Comments for EPA?

You may find the following suggestions helpful for preparing your comments:

- Explain your views as clearly as possible.
- Describe any assumptions that you used.
- Provide any technical information and/or data you used that support your views.
- If you estimate potential burden or costs, explain how you arrived at your estimate.
- Provide specific examples to illustrate your concerns.
- Offer alternatives.
- Make sure to submit your comments by the comment period deadline identified.
- To ensure proper receipt by EPA, identify the appropriate docket identification number in the subject line on the first page of your response. It would also be helpful if you provided the name, date, and **Federal Register** citation related to your comments.

XII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under section 3(f)(1) of Executive Order (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 Office of Management and Budget (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. This analysis is contained in the Draft Regulatory Impact Analysis, which is available in the docket for this rulemaking and at the docket internet address listed under **ADDRESSES** in the first part of this proposal. A more complete assessment of the costs and benefits associated with this Action will be completed for the Final Rule.

B. Paperwork Reduction Act

The information collection requirements in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document prepared by EPA has been assigned EPA ICR number 2333.01. A draft Supporting Statement has been placed in the docket for public comment.

The Agency proposes to collect information to ensure compliance with the provisions in this rule. This includes a variety of requirements for transportation fuel refiners, blenders, marketers, distributors, importers, and exporters. The types of information proposed to be collected includes, but is not limited to: registrations, periodic compliance reports, product transfer documentation, transactional information involving RINs and associated volumes of renewable fuel, and attest engagements. We invite comment on the proposed collection of information associated with this proposed rule.

Section 208(a) of the Clean Air Act requires that fuel producers provide information the Administrator may reasonably require to determine compliance with the regulations; submission of the information is therefore mandatory. We will consider confidential all information meeting the requirements of section 208(c) of the Clean Air Act.

As shown in Table XII.B–1, the total annual burden associated with this proposal is about 323,922 hours and $27,073,827, based on a projection of 20,216 respondents. The estimated burden for fuel producers is a total estimate for both new and existing reporting requirements. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

TABLE XII.B–1—ESTIMATED BURDEN FOR REPORTING AND RECORDKEEPING REQUIREMENTS

Industry sector	Number of respondents	Annual burden hours	Annual costs ($)
Fuels:			
Producers of renewable fuels	5,472	112,461	8,893,531
Importers of renewable fuels[a]	1,131	22,503	1,824,913
Obligated parties, exporters[b]	1,410	36,796	2,868,116
RIN owners[c]	12,083	148,542	13,102,447
Foreign refiners[d]	65	3,460	364,940
Foreign RIN owners	30	135	18,105
Retail stations (pump label)	25	25	1,775
Total	20,216	323,922	27,073,827

[a] Includes foreign producers.
[b] Refiners, exporters fall under this category.
[c] Includes blenders, brokers, marketers, etc. Anyone can own RINs.
[d] Includes small foreign refiners.

In addition to the estimates shown above, we have separately estimated the costs of potential third party disclosure that is associated with the proposed registration requirements explained in this notice of proposed rulemaking. Potentially affected parties include farmers, private forest owners, and other biofuel feedstock producers. We estimate a total of 43,466 respondents, 83,633 annual burden hours, and $5,937,943 in annual burden cost associated with the proposed third party disclosure. These estimates are explained in an addendum to the draft Supporting Statement, which has also been placed in the public docket.

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.

To comment on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques, EPA has established a public docket for this rule, which includes this proposed ICR, under Docket ID number EPA–HQ–OAR–2005–0161. Submit any comments related to the ICR for this proposed rule to EPA and OMB. See **ADDRESSES** at the beginning of this notice for where to submit comments to EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Office for EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after May 26, 2009, a comment to OMB is best assured of having its full effect if OMB receives it by June 25, 2009. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

C. Regulatory Flexibility Act

1. Overview

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201 (*see* table below); (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

The following table provides an overview of the primary SBA small business categories potentially affected by this regulation:

Industry[a]	Defined as small entity by SBA if:	NAICS[a] codes
Gasoline and diesel fuel refiners	≤1,500 employees	324110

[a] North American Industrial Classification System.

2. Background

Section 1501 of the Energy Policy Act of 2005 (EPAct) amended section 211 of the Clean Air Act (CAA) by adding section 211(o) which required the Environmental Protection Agency (EPA) to promulgate regulations implementing a renewable fuel program. EPAct specified that the regulations must ensure a specific volume of renewable fuel to be used in gasoline sold in the U.S. each year, with the total volume increasing over time. The goal of the program was to reduce dependence on foreign sources of petroleum, increase domestic sources of energy, and help transition to alternatives to petroleum in the transportation sector.

The final Renewable Fuels Standard (RFS1) program rule was published on May 1, 2007, and the program began on September 1, 2007. Per EPAct, the RFS1 program created a specific annual level for minimum renewable fuel use that increases over time—resulting in a requirement that 7.5 billion gallons of renewable fuel be blended into gasoline (for highway use only) by 2012. Under the RFS1 program, compliance is based on meeting the required annual renewable fuel volume percent standard (published annually in the **Federal Register** by EPA) through the use of Renewable Identification Numbers, or RINs, 38-digit serial numbers assigned to each batch of renewable fuel produced. For obligated parties (those who must meet the annual volume percent standard), RINs must be acquired to show compliance.

The Energy Independence and Security Act of 2007 (EISA) amended section 211(o), and the RFS program, by requiring higher volumes of renewable fuels, to result in 36 billion gallons of renewable fuel by 2022. EISA also expanded the purview of the RFS1 program by requiring that these renewable fuels be blended into gasoline and diesel fuel (both highway and nonroad). This expanded the pool of regulated entities, so the obligated parties under this RFS2 NPRM will now include certain refiners, importers, and blenders of these fuels that were not previously covered by the RFS1 program. In addition to the total renewable fuel standard required by EPAct, EISA added standards for three additional types of renewable fuels to the program (advanced biofuel, cellulosic biofuel, and biomass-based diesel) and requires compliance with all four standards.

Pursuant to section 603 of the RFA, EPA prepared an initial regulatory flexibility analysis (IRFA) that examines the impact of the proposed rule on small entities along with regulatory alternatives that could reduce that impact. The IRFA is available for review in the docket (in Chapter 7 of the Draft Regulatory Impact Analysis) and is summarized below.

As required by section 609(b) of the RFA, as amended by SBREFA, EPA also conducted outreach to small entities and convened a Small Business Advocacy Review Panel to obtain advice and recommendations of representatives of the small entities that potentially would be subject to the rule's requirements.

Consistent with the RFA/SBREFA requirements, the Panel evaluated the assembled materials and small-entity comments on issues related to elements of the IRFA. A copy of the Panel Report is included in the docket for this proposed rule, and a summary of the Panel process, and subsequent Panel recommendations, is summarized below.

3. Summary of Potentially Affected Small Entities

The small entities that will potentially be subject to the renewable fuel standard include: Domestic refiners that produce gasoline and/or diesel and importers of gasoline and/or diesel into the United States. Based on 2007 data, EPA believes that there are about 95 refiners of gasoline and diesel fuel. Of these, EPA believes that there are currently 21 refiners producing gasoline and/or diesel fuel that meet the SBA small entity definition of having 1,500 employees or less. Further, we believe that three of these refiners own refineries that do not meet the Congressional ''small refinery'' definition.[532] It should be noted that because of the dynamics in the refining industry (i.e., mergers and acquisitions), the actual number of refiners that ultimately qualify for small refiner status under the RFS2 program could be different than this initial estimate.

4. Potential Reporting, Recordkeeping, and Compliance

For any fuel control program, EPA must have assurance that any fuel produced meets all applicable standards and requirements, and that the fuel continues to meet those standards and requirements as it passes downstream through the distribution system to the ultimate end user. Registration, reporting, and recordkeeping are necessary to track compliance with the RFS2 requirements and transactions involving RINs. As discussed above in Sections III.J and IV.E, the proposed compliance requirements under the RFS2 program are in many ways similar to those required under the RFS1 program, with some modifications to account for the new requirements of EISA.

5. Related Federal Rules

We are aware of a few other current or proposed Federal rules that are related to the upcoming proposed rule. The primary federal rules that are related to the proposed RFS2 rule under consideration are the first Renewable Fuel Standard (RFS1) rule (72 FR 23900, May 1, 2007) and the RFS1 Technical Amendment Direct Final Rulemaking (73 FR 57248, October 2, 2008).[533]

6. Summary of SBREFA Panel Process and Panel Outreach

a. Significant Panel Findings

The Small Business Advocacy Review Panel (SBAR Panel, or the Panel) considered regulatory options and flexibilities to help mitigate potential adverse effects on small businesses as a result of this rule. During the SBREFA Panel process, the Panel sought out and received comments on the regulatory options and flexibilities that were presented to SERs and Panel members. The recommendations of the Panel are described below and are also located in Section 9 of the SBREFA Final Panel Report, which is available in the public docket.

b. Panel Process

As required by section 609(b) of the RFA, as amended by SBREFA, we also conducted outreach to small entities and convened an SBAR Panel to obtain advice and recommendations of representatives of the small entities that potentially would be subject to the rule's requirements. On July 9, 2008, EPA's Small Business Advocacy Chairperson convened a Panel under Section 609(b) of the RFA. In addition to the Chair, the Panel consisted of the Division Director of the Assessment and Standards Division of EPA's Office of Transportation and Air Quality, the Chief Counsel for Advocacy of the Small Business Administration, and the

[532] EPAct defined a ''small refinery'' as a refinery with a crude throughput of no more than 75,000 barrels of crude per day (at CAA section 211(o)(1)(K)). This definition is based on facility size and is different than SBA's small refiner definition (which is based on company size). A small refinery could be owned by a larger refiner that exceeds SBA's small entity standards. SBA's size standards were established to set apart those businesses which are most likely to be at an inherent economic disadvantage relative to larger businesses.

[533] This Direct Final Rule corrects minor typographical errors and provides clarification on existing provisions in the RFS1 regulations.

Administrator of the Office of Information and Regulatory Affairs within the Office of Management and Budget. As part of the SBAR Panel process, we conducted outreach with representatives from representatives of small businesses that would potentially be affected by the proposed rulemaking. We met with these Small Entity Representatives (SERs) to discuss the potential rulemaking approaches and potential options to decrease the impact of the rulemaking on their industries. We distributed outreach materials to the SERs; these materials included background on the rulemaking, possible regulatory approaches, and possible rulemaking alternatives. The Panel met with SERs from the industries that would be directly affected by the RFS2 rule on July 30, 2008 to discuss the outreach materials and receive feedback on the approaches and alternatives detailed in the outreach packet (the Panel also met with SERs on June 3, 2008 for an initial outreach meeting). The Panel received written comments from the SERs following the meeting in response to discussions had at the meeting and the questions posed to the SERs by the Agency. The SERs were specifically asked to provide comment on regulatory alternatives that could help to minimize the rule's impact on small businesses.

In general, SERs stated that they believed that small refiners would face challenges in meeting the new standards. More specifically, they voiced concerns with respect to the RIN program itself, uncertainty (with the required renewable fuel volumes, RIN availability, and cost), and the desire for a RIN system review.

The Panel's findings and discussions were based on the information that was available during the term of the Panel and issues that were raised by the SERs during the outreach meetings and in their comments. One concern that was raised by EPA with regard to provisions for small refiners in the RFS2 rule is that this rule presents a very different issue than the small refinery versus small refiner concept from RFS1. This issue deals with whether EPA has the authority to provide small refineries that are operated by a small refiner with an extension of time that would be different from (and more than) the temporary exemption specified by Congress in section 211(o)(9) for small refineries. For those small refiners who are covered by the small refinery provisions, Congress has specifically adopted a relief provision aimed at their refineries. This provides a temporary extension through December 31, 2010 and allows for further extensions only if certain criteria are met. EPA believes that providing small refineries (and thus, small refiners who own small refineries) with an additional exemption different from that provided by section 211(o)(9) raises concerns about inconsistency with the intent of Congress. Congress spoke directly to the relief that EPA may provide for small refineries, including those small refineries operated by small refiners, and limited it to a blanket exemption through December 31, 2010, with additional extensions if the criteria specified by Congress were met. An additional or different extension, relying on a more general provision in section 211(o)(3), would raise questions about consistency with the intent of Congress.

It was agreed that EPA should consider the issues raised by the SERs and discussions had by the Panel itself, and that EPA should consider comments on flexibility alternatives that would help to mitigate negative impacts on small businesses to the extent legally allowable by the Clean Air Act. Alternatives discussed throughout the Panel process included those offered in previous or current EPA rulemakings, as well as alternatives suggested by SERs and Panel members. A summary of these recommendations is detailed below, and a full discussion of the regulatory alternatives and hardship provisions discussed and recommended by the Panel can be found in the SBREFA Final Panel Report. A complete discussion of the provisions for which we are requesting comment and/or proposing in this action can be found in Section IV.B of this preamble. Also, the Panel Report includes all comments received from SERs (Appendix B of the Report) and summaries of the two outreach meetings that were held with the SERs. In accordance with the RFA/SBREFA requirements, the Panel evaluated the aforementioned materials and SER comments on issues related to the IRFA. The Panel's recommendations from the Final Panel Report are discussed below.

c. Panel Recommendations

The purpose of the Panel process is to solicit information as well as suggested flexibility options from the SERs, and the Panel recommended that EPA continue to do so during the development of the RFS2 rule. Recognizing the concerns about EPA's authority to provide extensions to a subset of small refineries (i.e., those that are owned by small refiners) different from that provided to small refineries in section 211(o)(9), the Panel recommended that EPA continue to evaluate this issue, and that EPA request comment on its authority and the appropriateness of providing extensions beyond those authorized by section 211(o)(9) for small refineries operated by a small refiner. The Panel also recommended that EPA propose to provide the same extension provision of 211(o)(9) to small refiners who do not own small refineries as is provided for small refiners who do own small refineries.

i. Delay in Standards

The RFS1 program regulations provide small refiners who operate small refineries as well as small refiners who do not operate small refineries with a temporary exemption from the standard through December 31, 2010. Small refiner SERs suggested that an additional temporary exemption for the RFS2 program would be beneficial to them in meeting the standards. EPA evaluated a temporary exemption for at least some of the four required RFS2 standards for small refiners. The Panel recommended that EPA propose a delay in the effective date of the standards until 2014 for small entities, to the maximum extent allowed by the statute. However, the Panel recognized that EPA has serious concerns about its authority to provide an extension of the temporary exemption for small refineries that is different from that provided in CAA section 211(o)(9), since Congress specifically addressed an extension for small refineries in that provision.

The Panel did recommend that EPA propose other avenues through which small refineries and small refiners could receive extensions of the temporary exemption. These avenues, as discussed in greater detail in Sections XII.C.6.c.v and vi below, are a possible extension of the temporary exemption for an additional two years following a study of small refineries by the Department of Energy (DOE) and provisions for case-by-case economic hardship relief.

ii. Phase-in

Small refiner SERs' suggested that a phase-in of the obligations applicable to small refiners would be beneficial for compliance, such that small refiners would comply by gradually meeting the standards on an incremental basis over a period of time, after which point they would comply fully with the RFS2 standards, EPA has serious concerns about its authority to allow for such a phase-in of the standards. CAA section 211(o)(3)(B) states that the renewable fuel obligation shall ''consist of a single applicable percentage that applies to all categories of persons specified'' as obligated parties. This kind of phase-in approach would result in different applicable percentages being applied to different obligated parties. Further, as discussed above, such a phase-in approach would provide more relief to small refineries operated by small refiners than that provided under the small refinery provision. Thus the Panel recommended that EPA should invite comment on a phase-in, but not propose such a provision.

iii. RIN-Related Flexibilities

The small refiner SERs requested that the proposed rule contain provisions for small refiners related to the RIN system, such as flexibilities in the RIN rollover cap percentage and allowing all small refiners to use RINs interchangeably. Currently in the RFS1 program, EPA allows for 20% of a previous year's RINs to be ''rolled over'' and used for compliance in the following year. A provision to allow for flexibilities in the rollover cap could include a higher RIN rollover cap for small refiners for some period of time or for at least some of the four standards. Since the concept of a rollover cap was not mandated by section 211(o), EPA believes that there may be an opportunity to provide appropriate flexibility in this area to small refiners under the RFS2 program but only if it is determined in the DOE small refinery study that there is a disproportionate effect warranting relief. The Panel recommended that EPA request comment on increasing the RIN rollover cap percentage for small refiners, and further that EPA should request comment on an appropriate level of that percentage.

The Panel recommended that EPA invite comment on allowing RINs to be used interchangeably for small refiners, but not propose this concept because under this approach small refiners would arguably be subject to a different applicable percentage than other obligated parties. This concept would also fail to require the four different standards mandated by Congress (e.g., conventional biofuel could not be used instead of cellulosic biofuel or biomass-based diesel).

iv. Program Review

With regard to the suggested program review, EPA raised the concern that this could lead to some redundancy since EPA is required to publish a notice of the applicable RFS standards in the Federal Register annually, and that this annual process will inevitably include an evaluation of the projected availability of renewable fuels. Nevertheless, the SBA and OMB Panel members stated that they believe that a program review could be helpful to small entities in providing them some insight to the RFS program's progress and alleviate some uncertainty regarding the RIN system. As EPA will be publishing a **Federal Register** notice annually, the Panel recommended that EPA include an update of RIN system progress (e.g., RIN trading, RIN availability, etc.) in this notice and that the results of this evaluation be considered in any request for case-by-case hardship relief.

v. Extensions of the Temporary Exemption Based on a Study of Small Refinery Impacts

The Panel recommended that EPA propose in the RFS2 program the provision at 40 CFR 80.1141(e) extending the RFS1 temporary exemption for at least two years for any small refinery that DOE determines would be subject to disproportionate economic hardship if required to comply with the RFS2 requirements.

Section 211(o)(9)(A)(ii) required that by December 31, 2008, DOE was to perform a study of the economic impacts of the RFS requirements on small refineries to assess and determine whether the RFS requirements would impose a disproportionate economic hardship on small refineries, and submit this study to EPA. Section 211(o)(9) also provided that small refineries found to be in a disproportionate economic hardship situation would receive an extension of the temporary exemption for at least two years.

The Panel also recommended that EPA work with DOE in the development of the small refinery study, specifically to communicate the comments that SERs raised during the Panel process.

vi. Extensions of the Temporary Exemption Based on Disproportionate Economic Hardship

While SERs did not specifically comment on the concept of hardship provisions for the upcoming proposal, the Panel noted that under CAA section 211(o)(9)(B) small refineries may petition EPA for case-by-case extensions of the small refinery temporary exemption on the basis of disproportionate economic hardship. Refiners may petition EPA for this case-by-case hardship relief at any time.

The Panel recommended that EPA propose in the RFS2 program a case-by-case hardship provision for small refineries similar to that provided at 40 CFR 80.1141(e)(1). The Panel also recommended that EPA propose a case-by-case hardship provision for small refiners that do not operate small refineries that is comparable to that provided for small refineries under section 211(o)(9)(B), using its discretion under CAA section 211(o)(3)(B). This would apply if EPA does not adopt an automatic extension for small refiners, and would allow those small refiners that do not operate small refineries to apply for the same kind of extension as a small refinery. The Panel recommended that EPA take into consideration the results of the annual update of RIN system progress and the DOE small refinery study in assessing such hardship applications.

We invite comments on all aspects of the proposal and its impacts on small entities.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), P.L. 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted.

Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

Today's proposal contains no Federal mandates (under the regulatory provisions of Title II of the UMRA) for

State, local, or tribal governments. The rule imposes no enforceable duty on any State, local or tribal governments. EPA has determined that this rule contains no regulatory requirements that might significantly or uniquely affect small governments. EPA has determined that this proposal contains a Federal mandate that may result in expenditures of $100 million or more for the private sector in any one year. EPA believes that the proposal represents the least costly, most cost-effective approach to achieve the statutory requirements of the rule. The costs and benefits associated with the proposal are discussed above and in the Draft Regulatory Impact Analysis, as required by the UMRA.

E. Executive Order 13132: Federalism

Executive Order 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 Executive Order 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 proposed 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 Executive Order 13132. Thus, Executive Order 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 solicits comment on this proposed rule from State and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.''

This proposed rule does not have tribal implications, as specified in Executive Order 13175. This rule will be implemented at the Federal level and impose compliance costs only on transportation fuel refiners, blenders, marketers, distributors, importers, and exporters. Tribal governments would be affected only to the extent they purchase and use regulated fuels. Thus, Executive Order 13175 does not apply to this rule. EPA specifically solicits additional comment on this proposed rule from tribal officials.

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 and because it implements specific standards established by Congress in statutes.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This rule is not a ''significant energy action'' as defined in Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (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. In fact, this rule has a positive effect on energy supply and use. By promoting the diversification of transportation fuels, this rule enhances energy supply. Therefore, we have concluded that this rule is not likely to have any adverse energy effects. Our energy effects analysis is described above in Section IX.

I. National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law No. 104–113, 12(d) (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 proposes changes to the Renewable Fuel Standard (RFS) program at Title 40 of the Code of Federal Regulations, Subpart K which already contains voluntary consensus standard ASTM D6751–06a ''Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels''. This standard was developed by ASTM International (originally known as the American Society for Testing and Materials), Subcommittee D02.E0, and was approved in August 2006. The standard may be obtained through the ASTM Web site (*www.astm.org*) or by calling ASTM at (610) 832–9585.

This proposed rulemaking does not propose to change this voluntary consensus standard, and does not involve any other technical standards. Therefore, EPA is not considering the use of any voluntary consensus standards other than that described above.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order (EO) 12898 (59 FR 7629 (Feb. 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 United States. EPA lacks the discretionary authority to address environmental justice in this proposed rulemaking since the Agency is implementing specific standards established by Congress in statutes. Although EPA lacks authority to modify today's regulatory decision on the basis of environmental justice considerations, EPA nevertheless determined that this proposed rule does not have a disproportionately high and adverse human health or environmental impact on minority or low-income populations.

XIII. Statutory Authority

Statutory authority for this action comes from section 211 of the Clean Air Act, 42 U.S.C. 7545. Additional support for the procedural and compliance related aspects of today's proposal, including the proposed recordkeeping requirements, come from Sections 114, 208, and 301(a) of the Clean Air Act, 42 U.S.C. 7414, 7542, and 7601(a).

List of Subjects in 40 CFR Part 80

Environmental protection, Air pollution control, Diesel fuel, Fuel additives, Gasoline, Imports, Incorporation by reference, Labeling, Motor vehicle pollution, Penalties, Reporting and recordkeeping requirements.

Dated: May 5, 2009.

Lisa P. Jackson,

Administrator.

For the reasons set forth in the preamble, 40 CFR part 80 is proposed to be amended as follows:

PART 80—REGULATION OF FUELS AND FUEL ADDITIVES

1. The authority citation for part 80 continues to read as follows:

Authority: 42 U.S.C. 7414, 7542, 7545, and 7601(a).

2. A new Subpart M is added to part 80 to read as follows:

Subpart M—Renewable Fuel Standard

Sec.

Subpart M—Renewable Fuel Standard

§ 80.1400 Applicability.

The provisions of this Subpart M shall apply for all renewable fuel produced on or after January 1, 2010, for all RINs generated after January 1, 2010, and for all renewable volume obligations and compliance periods starting with January 1, 2010. Except as provided otherwise in this Subpart M, the provisions of Subpart K of this Part 80 shall not apply for such renewable fuel, RINs, renewable volume obligations, or compliance periods.

§ 80.1401 Definitions.

The definitions of § 80.2 and of this section apply for the purposes of this subpart M. The definitions of this section do not apply to other subparts unless otherwise noted. Note that many terms defined here are common terms that have specific meanings under this subpart M (such as the terms ''co-processed,'' ''cropland,'' and ''yard waste''). The definitions follow:

Actual peak capacity means the maximum annual volume of renewable fuels produced from a specific renewable fuel production facility on an annual basis.

(1) For facilities that commenced construction prior to December 19, 2007 the maximum annual volume is for any year prior to 2008.

(2) For facilities that commenced construction after December 19, 2007, and are fired with natural gas, biomass, or a combination thereof, the maximum annual volume may be for any year after startup over the first three years of operation.

Advanced biofuel means renewable fuel, other than ethanol derived from cornstarch, that qualifies for a D code of 3 pursuant to § 80.1426(d).

Areas at risk of wildfire are areas located within, or within one mile of, forestland, tree plantation, or any other generally undeveloped tract of land that is at least one acre in size with substantial vegetative cover.

Baseline volume means the greater of nameplate capacity or actual peak capacity of a specific renewable fuel production facility.

(1) For facilities that commenced construction on or before December 19, 2007, the actual peak capacity may be for any year prior to 2008.

(2) For facilities that commenced construction after December 19, 2007, and are fired with natural gas, biomass, or a combination thereof, the actual peak capacity may be for any year after startup for the facility over the first three years of operation.

Biomass-based diesel means a renewable fuel which meets the requirements in paragraph (1) or (2) of this definition:

(1) A transportation fuel or fuel additive which is all of the following:

(i) Registered as a motor vehicle fuel or fuel additive under 40 CFR part 79.

(ii) A mono-alkyl ester and meets ASTM D–6751–07, entitled ''Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels.'' ASTM D–6751–07 is incorporated by reference. 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. A copy may be obtained from the American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania. A copy may be inspected at the EPA Docket Center, Docket No. EPA–HQ–OAR–2005–0161, EPA/DC, EPA West, Room 3334, 1301

Constitution Ave., NW., Washington, DC, or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 866–272–6272, or go to: *http://www.archives.gov/federal-register/cfr/ibr-locations.html.*

(iii) Intended for use in engines that are designed to run on conventional diesel fuel.

(iv) Qualifies for a D code of 2 pursuant to § 80.1426(d).

(2) A non-ester renewable diesel.

(3) Renewable fuel that is co-processed is not biomass-based diesel.

Carbon Capture and Storage (CCS) is the process of capturing carbon dioxide from an emission source, (typically) converting it to a supercritical state, transporting it to an injection site, and injecting it into deep subsurface rock formations for long-term storage.

Cellulosic biofuel means renewable fuel derived from any cellulose, hemi-cellulose, or lignin that is derived from renewable biomass and that qualifies for a D code of 1 pursuant to § 80.1426(d).

Combined heat and power (CHP), also known as cogeneration, refers to industrial processes in which byproduct heat that would otherwise be released into the environment is used for process heating and/or electricity production.

Commence construction, as applied to facilities that produce renewable fuel, means that the owner or operator has all necessary preconstruction approvals or permits (as defined at 40 CFR 52.21(a)(10)), that for multi-phased projects, the commencement of construction of one phase does not constitute commencement of construction of any later phase, unless each phase is mutually dependent for physical and chemical reasons only, and has satisfied either of the following:

(1) Begun, or caused to begin, a continuous program of actual construction on-site (as defined in 40 CFR 52.21(a)(11)) of the facility to be completed within a reasonable time.

(2) Entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of actual construction of the facility to be completed within a reasonable time.

Co-processed means that renewable biomass was simultaneously processed with petroleum feedstock in the same unit or units to produce a fuel that is partially renewable.

Crop residue is the residue left over from the harvesting of planted crops.

Cropland is land used for production of crops for harvest and includes cultivated cropland, such as for row crops or close-grown crops, and non-cultivated cropland, such as for horticultural crops.

Diesel refers to any and all of the products specified at § 80.1407(f).

Ecologically sensitive forestland means forestland that is:

(1) An ecological community listed in a document entitled ''Listing of Forest Ecological Communities Pursuant to 40 CFR 80.1401,'' (available in public docket EPA–HQ–OAR–2005–0161); or

(2) Old growth or late successional, characterized by trees at least 200 years in age.

Existing agricultural land is cropland, pastureland, or land enrolled in the Conservation Reserve Program (administered by the U.S. Department of Agriculture's Farm Service Agency) that was cleared or cultivated prior to December 19, 2007, and that, since December 19, 2007, has been continuously:

(1) Nonforested; and

(2) Actively managed as agricultural land or fallow, as evidenced by any of the following:

(i) Records of sales of planted crops, crop residue, or livestock, or records of purchases for land treatments such as fertilizer, weed control, or reseeding.

(ii) A written management plan for agricultural purposes.

(iii) Documented participation in an agricultural management program administered by a Federal, state, or local government agency.

(iv) Documented management in accordance with a certification program for agricultural products.

Export of renewable fuel means:

(1) Transfer of any renewable fuel to a location outside the contiguous 48 states and Hawaii; and

(2) Transfer of any renewable fuel from a location in the contiguous 48 states to Alaska or a United States territory, unless that state or territory has received an approval from the Administrator to opt-in to the renewable fuel program pursuant to § 80.1443.

Facility means all of the activities and equipment associated with the production of renewable fuel starting from the point of delivery of feedstock material to the point of final storage of the end product, which are located on one property, and are under the control of the same party (or parties under common control).

Fallow means cropland, pastureland, or land enrolled in the Conservation Reserve Program (administered by the U.S. Department of Agriculture's Farm Service Agency) that is intentionally left idle to regenerate for future agricultural purposes with no seeding or planting, harvesting, mowing, or treatment during the fallow period.

Forestland is generally undeveloped land covering a minimum area of 1 acre upon which the primary vegetative species are trees, including land that formerly had such tree cover and that will be regenerated. Forestland does not include tree plantations.

Gasoline refers to any and all of the products specified at § 80.1407(c).

Importers. An importer of transportation fuel or renewable fuel is:

(1) Any party who brings transportation fuel or renewable fuel into the 48 contiguous states of the United States and Hawaii, from a foreign country or from an area that has not opted in to the program requirements of this subpart pursuant to § 80.1443; and

(2) Any party who brings transportation fuel or renewable fuel into an area that has opted in to the program requirements of this subpart pursuant to § 80.1443.

Motor vehicle has the meaning given in Section 216(2) of the Clean Air Act (42 U.S.C. 7550(2)).

Nameplate capacity means:

(1) The maximum rated annual volume output of renewable fuel produced by a renewable fuel production facility under specific conditions as indicated in applicable air permits issued by the U.S. Environmental Protection Agency, state, or local air pollution control agencies and that govern the construction and/or operation of the renewable fuel facility.

(2) If the maximum rated annual volume output of renewable fuel is not specified in any applicable air permits issued by the U.S. Environmental Protection Agency, state, or local air pollution control agencies, then nameplate capacity is the actual peak capacity of the facility.

Neat renewable fuel is a renewable fuel to which only a de minimis amount of gasoline (as defined in Section 211(k)(10)(F) of the Clean Air Act (42 U.S.C. 7550)) or diesel fuel has been added.

Non-ester renewable diesel means renewable fuel which is all the following:

(1) Registered as a motor vehicle fuel or fuel additive under 40 CFR Part 79.

(2) Not a mono-alkyl ester.

(3) Intended for use in engines that are designed to run on conventional diesel fuel.

(4) Derived from nonpetroleum renewable resources.

(5) Qualifies for a D code of 3 as defined in § 80.1426(d).

Nonforested land means land that is not forestland.

Nonpetroleum renewable resources include, but are not limited to the following:

(1) Plant oils.

(2) Animal fats and animal wastes, including poultry fats and poultry wastes, and other waste materials.

Nonroad vehicle has the meaning given in Section 216(11) of the Clean Air Act (42 U.S.C. 7550(11)).

Ocean-going vessel means, for this subpart only, a vessel propelled by a Category 3 (C3) (as defined in 40 CFR 1042.901) marine engine that uses residual fuel (as defined at § 80.2(bbb)) or operates internationally. Note that ocean-going vessels may also include smaller engines such as Category 2 auxiliary engines.

Pastureland is land managed for the production of indigenous or introduced forage plants for livestock grazing or hay production, and to prevent succession to other plant types.

Planted crops are all annual or perennial agricultural crops that may be used as feedstocks for renewable fuel, such as grains, oilseeds, sugarcane, switchgrass, prairie grass, and other species providing that they were intentionally applied to the ground by humans either by direct application as seed or nursery stock, or through intentional natural seeding by mature plants left undisturbed for that purpose.

Planted trees are trees planted by humans from nursery stock or by seed either through direct application to the ground or by intentional natural seeding by mature trees left undisturbed for that purpose.

Pre-commercial thinnings are trees, including unhealthy or diseased trees, primarily removed to reduce stocking to concentrate growth on more desirable, healthy trees.

Renewable biomass means each of the following:

(1) Planted crops and crop residue harvested from existing agricultural land.

(2) Planted trees and slash from a tree plantation located on non-federal land (including land belonging to an Indian tribe or an Indian individual that is held in trust by the U.S. or subject to a restriction against alienation imposed by the U.S.) that was cleared at any time prior to December 19, 2007, and has been continuously actively managed since December 19, 2007. Active management is evidenced by any of the following:

(i) Records of sales of planted trees or slash, or records of purchases of seeds, seedlings, or other nursery stock.

(ii) A written management plan for silvicultural purposes.

(iii) Documented participation in a silvicultural program administered by a Federal, state, or local government agency.

(iv) Documented management in accordance with a certification program for silvicultural products.

(3) Animal waste material and animal byproducts.

(4) Slash and pre-commercial thinnings from non-federal forestland (including forestland belonging to an Indian tribe or an Indian individual, that are held in trust by the United States or subject to a restriction against alienation imposed by the United States) that is not ecologically sensitive forestland.

(5) Biomass (organic matter that is available on a renewable or recurring basis) obtained from within 200 feet of buildings, campgrounds, and other areas regularly occupied by people, or of public infrastructure, such as utility corridors, bridges, and roadways, in areas at risk of wildfire.

(6) Algae.

(7) Separated yard waste or food waste, including recycled cooking and trap grease.

Renewable fuel means a fuel which meets all of the following:

(1) Fuel that is produced from renewable biomass.

(2) Fuel that is used to replace or reduce the quantity of fossil fuel present in a transportation fuel, home heating oil, or jet fuel.

(3) Ethanol covered by this definition shall be denatured as required and defined in 27 CFR parts 19 through 21. Any volume of denaturant added to the undenatured ethanol by a producer or importer in excess of 5 volume percent shall not be included in the volume of ethanol for purposes of determining compliance with the requirements under this subpart.

Renewable Identification Number (RIN), is a unique number generated to represent a volume of renewable fuel pursuant to §§ 80.1425 and 80.1426.

(1) *Gallon-RIN* is a RIN that represents an individual gallon of renewable fuel; and

(2) *Batch-RIN* is a RIN that represents multiple gallon-RINs.

Slash is the residue, including treetops, branches, and bark, left on the ground after logging or accumulating as a result of a storm, fire, delimbing, or other similar disturbance.

Small refinery means a refinery for which the average aggregate daily crude oil throughput for calendar year 2006 (as determined by dividing the aggregate throughput for the calendar year by the number of days in the calendar year) does not exceed 75,000 barrels.

Transportation fuel means fuel for use in motor vehicles, motor vehicle engines, nonroad vehicles, or nonroad engines (except for ocean-going vessels).

Tree plantation is a stand of no fewer than 100 planted trees of similar age comprising one or two tree species or an area managed for growth of such trees covering a minimum of 1 acre.

Yard waste is leaves, sticks, pine needles, grass and hedge clippings, and similar waste from residential, commercial, or industrial areas.

§ 80.1402 [Reserved]

§ 80.1403 Which fuels are not subject to the 20% GHG thresholds?

(a) Pursuant to the definition of baseline volume in § 80.1401, the baseline volume of renewable fuel that is produced from facilities which commenced construction on or before December 19, 2007, shall not be subject to the 20 percent reduction in GHG emissions and shall be deemed grandfathered for purposes of generating RINs pursuant to § 80.1426(d)(7)(ii) if the owner or operator:

(1) Did not discontinue construction for a period of 18 months or more after December 19, 2007; and

(2) Completed construction within 36 months of December 19, 2007.

(b) The volume of ethanol that is produced from facilities which commenced construction after December 19, 2007 and on or before December 31, 2009, shall not be subject to the 20 percent reduction in GHG emissions and shall be deemed grandfathered for purposes of generating RINs pursuant to § 80.1426(d)(7)(ii) only if such facilities are fired with natural gas, biomass, or a combination thereof.

(c) The annual volume of renewable fuel during a calendar year from facilities described in paragraph (a) of this section that is beyond the baseline volume shall be subject to the 20 percent reduction in GHG emissions and such volume shall not be deemed grandfathered for purposes of generating RINs pursuant to § 80.1426(d)(7)(ii).

(d) For those facilities described in paragraph (a) of this section which produce ethanol and are fired with natural gas, biomass, or a combination thereof, increases in the annual volume of ethanol above the baseline volume during a calendar year shall not be subject to the 20 percent reduction in GHG emissions and shall be deemed grandfathered for purposes of generating RINs pursuant to § 80.1426(d)(7)(ii), provided that:

(1) The facility continues to be fired only with natural gas, biomass, or a combination thereof; and

(2) If the increases in volume at the facility are due to new construction, such new construction must have commenced on or before December 31, 2009.

(e) If there are any changes in the mix of renewable fuels produced by those facilities described in paragraph (d) of this section, only the ethanol volume will not be subject to the 20 percent reduction in GHG emissions and shall be deemed grandfathered for purposes of generating RINs pursuant to § 80.1426(d)(7)(ii).

§ 80.1404 [Reserved]

§ 80.1405 What are the Renewable Fuel Standards?

(a) *Renewable Fuel Standards for 2010.* (1) The value of the cellulosic biofuel standard for 2010 shall be 0.06 percent.

(2) The value of the biomass-based diesel standard for 2010 shall be 0.71 percent.

(3) The value of the advanced biofuel standard for 2010 shall be 0.59 percent.

(4) The value of the renewable fuel standard for 2010 shall be 8.01 percent.

(b) Beginning with the 2011 compliance period, EPA will calculate the value of the annual standards and publish these values in the **Federal Register** by November 30 of the year preceding the compliance period.

(c) EPA will base the calculation of the standards on information provided by the Energy Information Administration regarding projected gasoline and diesel volumes and projected volumes of renewable fuels expected to be used in gasoline and diesel blending for the upcoming year.

(d) EPA will calculate the annual renewable fuel standards using the following equations:

$$\mathrm{Std}_{\mathrm{CB,\,i}} = 100\% * \frac{\mathrm{RFV}_{\mathrm{CB,\,i}}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$\mathrm{Std}_{\mathrm{BBD,\,i}} = 100\% * \frac{\mathrm{RFV}_{\mathrm{BBD,\,i}}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$\mathrm{Std}_{\mathrm{AB,\,i}} = 100\% * \frac{\mathrm{RFV}_{\mathrm{AB,\,i}}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$\mathrm{Std}_{\mathrm{RF,\,i}} = 100\% * \frac{\mathrm{RFV}_{\mathrm{RF,\,i}}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

Where:

$\mathrm{Std}_{CB,i}$ = The cellulosic biofuel standard for year i, in percent.

$\mathrm{Std}_{BBD,i}$ = The biomass-based diesel standard for year i, in percent.

$\mathrm{Std}_{AB,i}$ = The advanced biofuel standard for year i, in percent.

$\mathrm{Std}_{RF,i}$ = The renewable fuel standard for year i, in percent.

$\mathrm{RFV}_{CB,i}$ = Annual volume of cellulosic biofuel required by section 211(o)(2)(B) of the Clean Air Act for year i, in gallons.

$\mathrm{RFV}_{BBD,i}$ = Annual volume of biomass-based diesel required by section 211(o)(2)(B) of the Clean Air Act for year i, in gallons.

$\mathrm{RFV}_{AB,i}$ = Annual volume of advanced biofuel required by section 211(o)(2)(B) of the Clean Air Act for year i, in gallons.

$\mathrm{RFV}_{RF,i}$ = Annual volume of renewable fuel required by section 211(o)(2)(B) of the Clean Air Act for year i, in gallons.

G_i = Amount of gasoline projected to be used in the 48 contiguous states and Hawaii, in year i, in gallons.

D_i = Amount of diesel projected to be used in the 48 contiguous states and Hawaii, in year i, in gallons.

RG_i = Amount of renewable fuel blended into gasoline that is projected to be consumed in the 48 contiguous states and Hawaii, in year i, in gallons.

RD_i = Amount of renewable fuel blended into diesel that is projected to be consumed in the 48 contiguous states and Hawaii, in year i, in gallons.

GS_i = Amount of gasoline projected to be used in Alaska or a U.S. territory, in year i, if the state or territory has opted-in or opts-in, in gallons.

RGS_i = Amount of renewable fuel blended into gasoline that is projected to be consumed in Alaska or a U.S. territory, in year i, if the state or territory opts-in, in gallons.

DS_i = Amount of diesel projected to be used in Alaska or a U.S. territory, in year i, if the state or territory has opted-in or opts-in, in gallons.

RDS_i = Amount of renewable fuel blended into diesel that is projected to be consumed in Alaska or a U.S. territory, in year i, if the state or territory opts-in, in gallons.

GE_i = The amount of gasoline projected to be produced by exempt small refineries and small refiners, in year i, in gallons in any year they are exempt per §§ 80.1441 and 80.1442, respectively. Assumed to equal 0.119 * $(G_i - RG_i)$.

DE_i = The amount of diesel fuel projected to be produced by exempt small refineries and small refiners in year i, in gallons, in any year they are exempt per §§ 80.1441 and 80.1442, respectively. Assumed to equal 0.152 * $(D_i - RD_i)$.

§ 80.1406 To whom do the Renewable Volume Obligations apply?

(a)(1) An obligated party is any refiner that produces gasoline or diesel fuel within the 48 contiguous states or Hawaii, or any importer that imports gasoline or diesel fuel into the 48 contiguous states or Hawaii. A party that simply adds renewable fuel to gasoline or diesel fuel, as defined in § 80.1407(c) or (f), is not an obligated party.

(2) If the Administrator approves a petition of Alaska or a United States territory to opt-in to the renewable fuel program under the provisions in § 80.1443, then ''obligated party'' shall also include any refiner that produces gasoline or diesel fuel within that state or territory, or any importer that imports gasoline or diesel fuel into that state or territory.

(b) For each compliance period starting with 2010, an obligated party is required to demonstrate, pursuant to § 80.1427, that it has satisfied the Renewable Volume Obligations for that compliance period, as specified in § 80.1407(a).

(c) An obligated party may comply with the requirements of paragraph (b) of this section for all of its refineries in the aggregate, or for each refinery individually.

(d) An obligated party must comply with the requirements of paragraph (b) of this section for all of its imported gasoline or diesel fuel in the aggregate.

(e) An obligated party that is both a refiner and importer must comply with the requirements of paragraph (b) of this section for its imported gasoline or diesel fuel separately from gasoline or diesel fuel produced by its refinery or refineries.

(f) Where a refinery or import facility is jointly owned by two or more parties, the requirements of paragraph (b) of this section may be met by one of the joint owners for all of the gasoline or diesel fuel produced/imported at the facility, or each party may meet the requirements of paragraph (b) of this section for the portion of the gasoline or diesel fuel that it owns, as long as all of the gasoline or diesel fuel produced/imported at the facility is accounted for in determining the Renewable Volume Obligations under § 80.1407.

(g) The requirements in paragraph (b) of this section apply to the following compliance periods: Beginning in 2010, and every year thereafter, the compliance period is January 1 through December 31.

(h) A party that exports renewable fuel (pursuant to the definition of an exporter of renewable fuel in § 80.1401) shall demonstrate, pursuant to § 80.1427, that it has satisfied the Renewable Volume Obligations for each compliance period as specified in § 80.1430(b).

§ 80.1407 How are the Renewable Volume Obligations calculated?

(a) The Renewable Volume Obligations for an obligated party are determined according to the following formulas:

(1) *Cellulosic biofuel.*

$RVO_{CB,i} = (RFStd_{CB,i} * (GV_i + DV_i)) + D_{CB,i-1}$

Where:

$RVO_{CB,i}$ = The Renewable Volume Obligation for cellulosic biofuel for an obligated party for calendar year i, in gallons.

$RFStd_{CB,i}$ = The standard for cellulosic biofuel for calendar year i, determined by EPA pursuant to § 80.1405, in percent.

GV_i = The non-renewable gasoline volume, determined in accordance with paragraphs (b), (c), and (d) of this section, which is produced in or imported into the 48 contiguous states or Hawaii by an obligated party in calendar year i, in gallons.

DV_i = The diesel non-renewable volume, determined in accordance with paragraphs (e) and (f) of this section, produced in or imported into the 48 contiguous states or Hawaii by an obligated party in calendar year i, in gallons.

$D_{CB,i-1}$ = Deficit carryover from the previous year for cellulosic biofuel, in gallons.

(2) *Biomass-based diesel.*

$RVO_{BBD,i} = (RFStd_{BBD,i} * (GV_i + DV_i)) + D_{BBD,i-1}$

Where:

$RVO_{BBD,i}$ = The Renewable Volume Obligation for biomass-based diesel for an obligated party for calendar year i, in gallons.

$RFStd_{BBD,i}$ = The standard for biomass-based diesel for calendar year i, determined by EPA pursuant to § 80.1405, in percent.

GV_i = The non-renewable gasoline volume, determined in accordance with paragraphs (b), (c), and (d) of this section, which is produced in or imported into the 48 contiguous states or Hawaii by an obligated party in calendar year i, in gallons.

DV_i = The diesel non-renewable volume, determined in accordance with paragraphs (e) and (f) of this section, produced in or imported into the 48 contiguous states or Hawaii by an obligated party in calendar year i, in gallons.

$D_{BBD,i-1}$ = Deficit carryover from the previous year for biomass-based diesel, in gallons.

(3) *Advanced biofuel.*

$RVO_{AB,i} = (RFStd_{AB,i} * (GV_i + DV_i)) + D_{AB,i-1}$

Where:

$RVO_{AB,i}$ = The Renewable Volume Obligation for advanced biofuel for an obligated party for calendar year i, in gallons.

$RFStd_{AB,i}$ = The standard for advanced biofuel for calendar year i, determined by EPA pursuant to § 80.1405, in percent.

GV_i = The non-renewable gasoline volume, determined in accordance with paragraphs (b), (c), and (d) of this section, which is produced in or imported into the 48 contiguous states or Hawaii by an obligated party in calendar year i, in gallons.

DV_i = The diesel non-renewable volume, determined in accordance with paragraphs (e) and (f) of this section, produced in or imported into the 48 contiguous states or Hawaii by an obligated party in calendar year i, in gallons.

$D_{AB,i-1}$ = Deficit carryover from the previous year for advanced biofuel, in gallons.

(4) *Renewable fuel.*

$RVO_{RF,i} = (RFStd_{RF,i} * (GV_i + DV_i)) + D_{RF,i-1}$

Where:

$RVO_{RF,i}$ = The Renewable Volume Obligation for renewable fuel for an obligated party for calendar year i, in gallons.

$RFStd_{RF,i}$ = The standard for renewable fuel for calendar year i, determined by EPA pursuant to § 80.1405, in percent.

GV_i = The non-renewable gasoline volume, determined in accordance with paragraphs (b), (c), and (d) of this section, which is produced in or imported into the 48 contiguous states or Hawaii by an obligated party in calendar year i, in gallons.

DV_i = The diesel non-renewable volume, determined in accordance with paragraphs (e) and (f) of this section, produced in or imported into the 48 contiguous states or Hawaii by an obligated party in calendar year i, in gallons.

$D_{RF,i-1}$ = Deficit carryover from the previous year for renewable fuel, in gallons.

(b) The non-renewable gasoline volume for an obligated party for a given year, GV_i, specified in paragraph (a) of this section is calculated as follows:

$$GV_i = \sum_{x=1}^{n} G_x - \sum_{y=1}^{m} RBG_y$$

Where:

x = Individual batch of gasoline produced or imported in calendar year i.

n = Total number of batches of gasoline produced or imported in calendar year i.

G_x = Volume of batch x of gasoline produced or imported, as defined in paragraph (c) of this section, in gallons.

y = Individual batch of renewable fuel blended into gasoline in calendar year i.

m = Total number of batches of renewable fuel blended into gasoline in calendar year i.

RBG_y = Volume of batch y of renewable fuel blended into gasoline, in gallons.

(c) All of the following products that are produced or imported during a compliance period, collectively called ‘‘gasoline’’ for the purposes of this section (unless otherwise specified), are to be included (but not double-counted) in the volume used to calculate a party's Renewable Volume Obligations under paragraph (a) of this section, except as provided in paragraph (d) of this section:

(1) Reformulated gasoline, whether or not renewable fuel is later added to it.

(2) Conventional gasoline, whether or not renewable fuel is later added to it.

(3) Reformulated gasoline blendstock that becomes finished reformulated gasoline upon the addition of oxygenate (RBOB).

(4) Conventional gasoline blendstock that becomes finished conventional gasoline upon the addition of oxygenate (CBOB).

(5) Blendstock (including butane and gasoline treated as blendstock (GTAB)) that has been combined with other blendstock and/or finished gasoline to produce gasoline.

(6) Any gasoline, or any unfinished gasoline that becomes finished gasoline upon the addition of oxygenate, that is

produced or imported to comply with a state or local fuels program.

(d) The following products are not included in the volume of gasoline produced or imported used to calculate a party's renewable volume obligation under paragraph (a) of this section:

(1) Any renewable fuel as defined in § 80.1401.

(2) Blendstock that has not been combined with other blendstock or finished gasoline to produce gasoline.

(3) Gasoline produced or imported for use in Alaska, the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Marianas, unless the area has opted into the RFS program under § 80.1443.

(4) Gasoline produced by a small refinery that has an exemption under § 80.1441 or an approved small refiner that has an exemption under § 80.1442 until January 1, 2011 (or later, for small refineries, if their exemption is extended pursuant to § 80.1441(h)).

(5) Gasoline exported for use outside the 48 United States and Hawaii, and gasoline exported for use outside Alaska, the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Marianas, if the area has opted into the RFS program under § 80.1443.

(6) For blenders, the volume of finished gasoline, RBOB, or CBOB to which a blender adds blendstocks.

(7) The gasoline portion of transmix produced by a transmix processor, or the transmix blended into gasoline by a transmix blender, under § 80.84.

(e) The diesel non-renewable volume for an obligated party for a given year, DV_i, specified in paragraph (a) of this section is calculated as follows:

$$DV_i = \sum_{x=1}^{n} D_x - \sum_{y=1}^{m} RBD_y$$

Where:

x = Individual batch of diesel produced or imported in calendar year i.

n = Total number of batches of diesel produced or imported in calendar year i.

D_x = Volume of batch x of diesel produced or imported, as defined in paragraph (f) of this section, in gallons.

y = Individual batch of renewable fuel blended into diesel in calendar year i.

m = Total number of batches of renewable fuel blended into diesel in calendar year i.

RBD_y = Volume of batch y of renewable fuel blended into diesel, in gallons.

(f) All products meeting the definition of *MVNRLM diesel fuel* at § 80.2(qqq) that are produced or imported during a compliance period, collectively called "diesel fuel" for the purposes of this section (unless otherwise specified), are to be included (but not double-counted) in the volume used to calculate a party's Renewable Volume Obligations under paragraph (a) of this section.

§§ 80.1408–80.1414 [Reserved]

§ 80.1415 How are equivalence values assigned to renewable fuel?

(a)(1) Each gallon of a renewable fuel, or gallon equivalent pursuant to paragraph (c) of this section, shall be assigned an equivalence value by the producer or importer pursuant to paragraph (b) or (c) of this section.

(2) The equivalence value is a number that is used to determine how many gallon–RINs can be generated for a batch of renewable fuel according to § 80.1426.

(b) All renewable fuels shall have an equivalence value of 1.0.

(c) A gallon of renewable fuel is a physically measured unit of volume for any fuel that exists as a liquid at 60 °F and 1 atm, but represents 77,930 Btu (lower heating value) for any fuel that exists as a gas at 60 °F and 1 atm.

§ 80.1416 Treatment of parties who produce or import new renewable fuels and pathways.

(a)(1) Each renewable fuel producer or importer that produces or imports a new renewable fuel, or uses a new pathway that can not qualify for a D code as defined in § 80.1426(d), must apply to use a D code as specified in paragraph (b) of this section.

(2) EPA will review the application and may allow the use of an appropriate D code for the combination of fuel type, feedstock, and production process.

(3) Except as provided in paragraph (c) of this section, parties that must apply to use a D code pursuant to paragraph (b) of this section may not generate RINs for that new fuel or new combination fuel type, feedstock, and production process until the Agency has reviewed the application and updated Table 1 to § 80.1426.

(b)(1) The application for a new renewable fuel or pathway shall include all the following:

(i) A completed facility registration under § 80.1450(b).

(ii) A technical justification that includes a description of the renewable fuel, feedstock(s) used to make it, and the production process.

(iii) Any additional information that the Agency needs to complete a lifecycle Greenhouse Gas assessment of the new fuel or pathway.

(2) A company may only submit one application per pathway. If EPA determines the application to be incomplete, per paragraph (b)(4) of this section, then the company may resubmit.

(3) The application must be signed and certified as meeting all the applicable requirements of this subpart by a responsible corporate officer of the applicant organization.

(4) If EPA determines that the application is incomplete then EPA will notify the applicant in writing that the application is incomplete and will not be reviewed further. However, an amended application that corrects the omission may be re-submitted for EPA review.

(5) If the fuel or pathway described in the application does not meet the definition of renewable fuel in § 80.1401, then EPA will notify the applicant in writing that the application is denied and will not be reviewed further.

(c)(1) A producer may use a temporary D code pending EPA review of an application under paragraph (b) of this section if the producer is producing renewable fuel from a fuel type and feedstock combination listed in Table 1 to § 80.1426, but where the renewable fuel producer's production process is not listed. A producer using a temporary D code, must do all the following:

(i) Provide information necessary under paragraph (b) of this section and register under 40 CFR part 79 before introducing the fuel into commerce.

(ii) Generate RINs using the temporary D code for all renewable fuel produced using this combination fuel type, feedstock, and production process.

(iii) When Table 1 to § 80.1426 has been updated to include the new fuel pathway, cease to use the temporary D code and use the applicable D code in the table.

(iv) For existing fuel type and feedstock combinations that apply to more than one D code, the producer must use the highest numerical value from the applicable D codes as the temporary D code.

(2) Except if the application is deemed incomplete or denied pursuant to paragraph (b)(3) or (b)(4) of this section, if Table 1 to § 80.1426 is not updated within 5 years of the initial receipt of a company's application, the company must stop using the temporary D code.

(3) A producer whose fuel pathway is ethanol made from starches in a process that uses natural gas or coal for process heat may not use a temporary D code for their fuel pathway.

(4) EPA may revoke the authority provided by this section for use of a temporary D code at any time if any of the following occur:

(i) EPA determines that the fuel or pathway described in the application does not meet the definition of renewable fuel in § 80.1401.

(ii) EPA discovers adverse health effects unique to the fuel or pathway.

(iii) The information provided by the applicant on the pathway in paragraph (b) of this section is deemed false or incorrect.

(d) The application under this section shall be submitted on forms and following procedures as prescribed by EPA.

§§ 80.1417–80.1424 [Reserved]

§ 80.1425 Renewable Identification Numbers (RINs).

Each RIN is a 38-character numeric code of the following form:

KYYYYCCCCFFFFFBBBBBRRDSSSSSSSSEEEEEEEE

(a) K is a number identifying the type of RIN as follows:

(1) K has the value of 1 when the RIN is assigned to a volume of renewable fuel pursuant to §§ 80.1426(e) and 80.1428(a).

(2) K has the value of 2 when the RIN has been separated from a volume of renewable fuel pursuant to § 80.1429.

(b) YYYY is the calendar year in which the batch of renewable fuel was produced or imported. YYYY also represents the year in which the RIN was originally generated.

(c) CCCC is the registration number assigned, according to § 80.1450, to the producer or importer of the batch of renewable fuel.

(d) FFFFF is the registration number assigned, according to § 80.1450, to the facility at which the batch of renewable fuel was produced or imported.

(e) BBBBB is a serial number assigned to the batch which is chosen by the producer or importer of the batch such that no two batches have the same value in a given calendar year.

(f) RR is a number representing 10 times the equivalence value of the renewable fuel as specified in § 80.1415.

(g) D is a number determined according to § 80.1426(d) and identifying the type of renewable fuel, as follows:

(1) D has the value of 1 to denote fuel categorized as cellulosic biofuel.

(2) D has the value of 2 to denote fuel categorized as biomass-based diesel.

(3) D has the value of 3 to denote fuel categorized as advanced biofuel.

(4) D has the value of 4 to denote fuel categorized as renewable fuel.

(h) SSSSSSSS is a number representing the first gallon-RIN associated with a batch of renewable fuel.

(i) EEEEEEEE is a number representing the last gallon-RIN associated with a batch of renewable fuel. EEEEEEEE will be identical to SSSSSSSS if the batch-RIN represents a single gallon-RIN. Assign the value of EEEEEEEE as described in § 80.1426.

§ 80.1426 How are RINs generated and assigned to batches of renewable fuel by renewable fuel producers or importers?

(a) *Regional applicability.* (1) Except as provided in paragraph (b) of this section, a RIN must be generated by a renewable fuel producer or importer for every batch of fuel that meets the definition of renewable fuel that is produced or imported for use as transportation fuel, home heating oil, or jet fuel in the 48 contiguous states or Hawaii.

(2) If the Administrator approves a petition of Alaska or a United States territory to opt-in to the renewable fuel program under the provisions in § 80.1443, then the requirements of paragraph (a)(1) of this section shall also apply to renewable fuel produced or imported for use as transportation fuel, home heating oil, or jet fuel in that state or territory beginning in the next calendar year.

(b) *Cases in which RINs are not generated.* (1) *Volume threshold.* Renewable fuel producers that produce less than 10,000 gallons of renewable fuel each year, and importers that import less than 10,000 gallons of renewable fuel each year, are not required to generate and assign RINs to batches of renewable fuel. Such producers and importers are also exempt from the registration, reporting, and recordkeeping requirements of §§ 80.1450 through 80.1452, and the attest engagement requirements of § 80.1464. However, for those producers and importers that own RINs or voluntarily generate and assign RINs, all the requirements of this subpart apply.

(2) Fuel producers and importers shall not generate RINs for fuel that they produce or import for which they have made a demonstration under § 80.1451(c) that the feedstocks used to produce the fuel are not renewable biomass (as defined in § 80.1401).

(3) Fuel producers and importers may not generate RINs for fuel that is not renewable fuel.

(4) Importers shall not import or generate RINs for fuel imported from a foreign producer that is not registered with EPA as required in § 80.1450.

(5) Importers shall not generate RINs for renewable fuel that has already been assigned RINs by a foreign producer.

(c) *Definition of batch.* For the purposes of this section and § 80.1425, a ''batch of renewable fuel'' is a volume of renewable fuel that has been assigned a unique RIN code BBBBB within a calendar year by the producer or importer of the renewable fuel in accordance with the provisions of this section and § 80.1425.

(1) The number of gallon-RINs generated for a batch of renewable fuel may not exceed 99,999,999.

(2) A batch of renewable fuel cannot represent renewable fuel produced or imported in excess of one calendar month.

(d) *Generation of RINs.* (1) Producers and importers of fuel made from renewable feedstocks must determine for each batch of fuel produced or imported whether or not the fuel is renewable fuel (as defined in § 80.1401), including a determination of whether or not the feedstock used to make the fuel is renewable biomass (as defined § 80.1401). Except as provided in paragraph (b) of this section, the producer or importer of a batch of renewable fuel must generate a RIN for that batch.

(i) Domestic producers must generate RINs for all renewable fuel that they produce.

(ii) Importers must generate RINs for all renewable fuel that they import that has not been assigned RINs by a foreign producer, including any renewable fuel contained in imported transportation fuel.

(iii) Foreign producers may generate RINs for any renewable fuel that they export to the 48 contiguous states of the United States or Hawaii.

(2) A party generating a RIN shall specify the appropriate numerical values for each component of the RIN in accordance with the provisions of § 80.1425(a) and this paragraph (d).

(3) *Applicable pathways.* D codes shall be used in RINs generated by producers or importers of renewable fuel according to the pathways listed in Table 1 to this section.

TABLE 1 TO § 80.1426—APPLICABLE D CODES FOR EACH FUEL PATHWAY FOR USE IN GENERATING RINS

Fuel type	Feedstock	Production process requirements	D code
Ethanol	Starch from corn, wheat, barley, oats, rice, or sorghum	—Process heat derived from biomass	4
Ethanol	Starch from corn, wheat, barley, oats, rice, or sorghum	—Dry mill plant —Process heat derived from natural gas —Combined heat and power (CHP) —Fractionation of feedstocks —Some or all distillers grains are dried	4
Ethanol	Starch from corn, wheat, barley, oats, rice, or sorghum	—Dry mill plant —Process heat derived from natural gas —All distillers grains are wet	4
Ethanol	Starch from corn, wheat, barley, oats, rice, or sorghum	—Dry mill plant —Process heat derived from coal —Combined heat and power (CHP) —Fractionation of feedstocks —Membrane separation of ethanol —Raw starch hydrolysis —Some or all distillers grains are dried	4
Ethanol	Starch from corn, wheat, barley, oats, rice, or sorghum	—Dry mill plant —Process heat derived from coal —Combined heat and power (CHP) —Fractionation of feedstocks —Membrane separation of ethanol —All distillers grains are wet	4
Ethanol	Cellulose and hemicellulose from corn stover, switchgrass, miscanthus, wheat straw, rice straw, sugarcane bagasse, slash, pre-commercial thinnings, yard waste, or planted trees.	—Enzymatic hydrolysis of cellulose —Fermentation of sugars —Process heat derived from lignin	1
Ethanol	Cellulose and hemicellulose from corn stover, switchgrass, miscanthus, wheat straw, rice straw, sugarcane bagasse, slash, pre-commercial thinnings, yard waste, or planted trees.	—Thermochemical gasification of biomass. —Fischer-Tropsch process	1
Ethanol	Sugarcane sugar	—Process heat derived from sugarcane bagasse	3
Biodiesel (mono alkyl ester).	Waste grease, waste oils, tallow, chicken fat, or non-food-grade corn oil	—Transesterification	2
Biodiesel (mono alkyl ester).	Soybean oil and other virgin plant oils	—Transesterification	4
Cellulosic diesel	Cellulose and hemicellulose from corn stover, switchgrass, miscanthus, wheat straw, rice straw, sugarcane bagasse, slash, pre-commercial thinnings, yard waste, or planted trees.	—Thermochemical gasification of biomass. —Fischer-Tropsch process —Catalytic depolymerization	1 or 2
Non-ester renewable diesel.	Waste grease, waste oils, tallow, chicken fat, or non-food-grade corn oil	—Hydrotreating —Dedicated facility that processes only renewable biomass.	2
Non-ester renewable diesel.	Waste grease, waste oils, tallow, chicken fat, or non-food-grade corn oil	—Hydrotreating —Co-processing facility that also processes petroleum feedstocks.	3
Non-ester renewable diesel.	Soybean oil and other virgin plant oils	—Hydrotreating	4
Cellulosic gasoline	Cellulose and hemicellulose from corn stover, switchgrass, miscanthus, wheat straw, rice straw, sugarcane bagasse, slash, pre-commercial thinnings, yard waste, or planted trees.	—Thermochemical gasification of biomass. —Fischer-Tropsch process —Catalytic depolymerization	1

(4) *Producers whose operations can be described by a single pathway.*

(i) The number of gallon-RINs that shall be generated for a given batch of renewable fuel shall be equal to a volume calculated according to the following formula:

$V_{RIN} = EV * V_s$

Where:

V_{RIN} = RIN volume, in gallons, for use in determining the number of gallon-RINs that shall be generated.

EV = Equivalence value for the renewable fuel per § 80.1415.

V_s = Standardized volume of the batch of renewable fuel at 60 °F, in gallons, calculated in accordance with paragraph (d)(10) of this section.

(ii) The D code that shall be used in the RINs generated shall be the D code specified in Table 1 to this section which corresponds to the pathway that describes the producer's operations.

(5) *Producers whose operations can be described by two or more pathways.* (i) The D codes that shall be used in the RINs generated within a calendar year shall be the D codes specified in Table 1 to this section which correspond to the pathways that describe the producer's operations throughout that calendar year.

(ii) If all the pathways describing the producer's operations have the same D code, then that D code shall be used in all the RINs generated. The number of gallon-RINs that shall be generated for a given batch of renewable fuel in this case shall be equal to a volume calculated according to the following formula:

$V_{RIN} = EV * V_s$

Where:

V_{RIN} = RIN volume, in gallons, for use in determining the number of gallon-RINs that shall be generated.

EV = Equivalence value for the renewable fuel per § 80.1415.

V_s = Standardized volume of the batch of renewable fuel at 60 °F, in gallons, calculated in accordance with paragraph (d)(10) of this section.

(iii) If the pathway applicable to a producer changes on a specific date, such that one pathway applies before the date and another pathway applies on and after the date, then the applicable D code used in generating RINs must change on the date that the change in pathway occurs. The number of gallon-RINs that shall be generated for a given batch of renewable fuel in this case shall be equal to a volume calculated according to the following formula:

$V_{RIN} = EV * V_s$

Where:

V_{RIN} = RIN volume, in gallons, for use in determining the number of gallon-RINs that shall be generated for a batch with a single applicable D code.

EV = Equivalence value for the renewable fuel per § 80.1415.

V_s = Standardized volume of the batch of renewable fuel at 60 °F, in gallons, calculated in accordance with paragraph (d)(10) of this section.

(iv) If a producer produces two or more different types of renewable fuel whose volumes can be measured separately, then separate values for V_{RIN} shall be calculated for each batch of each type of renewable fuel according to formulas in Table 2 to this section:

TABLE 2 TO § 80.1426—NUMBER OF GALLON-RINS TO ASSIGN TO BATCH-RINS WITH D CODES DEPENDENT ON FUEL TYPE

D code to use in batch-RIN	Number of gallon-RINs
D = 1	$V_{RIN,\ CB} = EV *V_{s,\ CB}$
D = 2	$V_{RIN,\ BBD} = EV *V_{s,\ BBD}$
D = 3	$V_{RIN,\ AB} = EV *V_{s,\ RF}$
D = 4	$V_{RIN,\ RF} = EV *V_{s,\ RF}$

Where:

$V_{RIN,CB}$ = RIN volume, in gallons, for use determining the number of gallon-RINs that shall be generated for a batch of cellulosic biofuel with a D code of 1.

$V_{RIN,BBD}$ = RIN volume, in gallons, for use determining the number of gallon-RINs that shall be generated for a batch of biomass-based diesel with a D code of 2.

$V_{RIN,AB}$ = RIN volume, in gallons, for use determining the number of gallon-RINs that shall be generated for a batch of advanced biofuel with a D code of 3.

$V_{RIN,RF}$ = RIN volume, in gallons, for use determining the number of gallon-RINs that shall be generated for a batch of renewable fuel with a D code of 4.

EV = Equivalence value for the renewable fuel per § 80.1415.

$V_{s,CB}$ = Standardized volume of the batch of renewable fuel at 60 °F that must be assigned a D code of 1 based on its fuel type, in gallons, calculated in accordance with paragraph (d)(10) of this section.

$V_{s,BBD}$ = Standardized volume of the batch of renewable fuel at 60 °F that must be assigned a D code of 2 based on its fuel type, in gallons, calculated in accordance with paragraph (d)(10) of this section.

$V_{s,AB}$ = Standardized volume of the batch of renewable fuel at 60 °F that must be assigned a D code of 3 based on its fuel type, in gallons, calculated in accordance with paragraph (d)(10) of this section.

$V_{s,RF}$ = Standardized volume of the batch of renewable fuel at 60 °F that must be assigned a D code of 4 based on its fuel type, in gallons, calculated in accordance with paragraph (d)(10) of this section.

(v) If a producer produces a single type of renewable fuel using two or more different feedstocks which are processed simultaneously, then the number of gallon-RINs that shall be generated for each batch of renewable fuel and assigned a particular D code shall be determined according to the formulas in Table 3 to this section.

Table 3 to §80.1426

Number of gallon-RINs to assign to batch-RINs with D codes dependent on feedstock

D code to use in batch-RIN	Number of gallon-RINs
D = 1	$V_{RIN,\,CB} = EV * V_s * \left(\frac{FE_1}{FE_1 + FE_2 + FE_3 + FE_4}\right)$
D = 2	$V_{RIN,\,BBD} = EV * V_s * \left(\frac{FE_2}{FE_1 + FE_2 + FE_3 + FE_4}\right)$
D = 3	$V_{RIN,\,AB} = EV * V_s * \left(\frac{FE_3}{FE_1 + FE_2 + FE_3 + FE_4}\right)$
D = 4	$V_{RIN,\,RF} = EV * V_s * \left(\frac{FE_4}{FE_1 + FE_2 + FE_3 + FE_4}\right)$

Where:

$V_{RIN,CB}$ = RIN volume, in gallons, for use in determining the number of gallon-RINs that shall be generated for a batch of cellulosic biofuel with a D code of 1.

$V_{RIN,BBD}$ = RIN volume, in gallons, for use in determining the number of gallon-RINs that shall be generated for a batch of biomass-based diesel with a D code of 2.

$V_{RIN,AB}$ = RIN volume, in gallons, for use in determining the number of gallon-RINs that shall be generated for a batch of advanced biofuel with a D code of 3.

$V_{RIN,RF}$ = RIN volume, in gallons, for use in determining the number of gallon-RINs that shall be generated for a batch of renewable fuel with a D code of 4.

EV = Equivalence value for the renewable fuel per § 80.1415.

V_s = Standardized volume of the batch of renewable fuel at 60 °F, in gallons, calculated in accordance with paragraph (d)(10) of this section.

FE_1 = Feedstock energy from all feedstocks whose pathways have been assigned a D code of 1 under Table 1 to this section, in Btu.

FE_2 = Feedstock energy from all feedstocks whose pathways have been assigned a D code of 2 under Table 1 to this section, in Btu.

FE_3 = Feedstock energy from all feedstocks whose pathways have been assigned a D code of 3 under Table 1 to this section, in Btu.

FE_4 = Feedstock energy from all feedstocks whose pathways have been assigned a D code of 4 under Table 1 to this section, in Btu.

Feedstock energy values, FE, shall be calculated according to the following formula:

$FE = M * CF * E$

Where:

FE = Feedstock energy, in Btu.
M = Mass of feedstock, in pounds.
CF = Converted Fraction in annual average mass percent, representing that portion of the feedstock that is estimated to be converted into renewable fuel by the producer.
E = Energy content of the fuel precursor fraction for the feedstock in annual average Btu/lb.

(6) *Producers who co-process renewable biomass and fossil fuels simultaneously to produce a transportation fuel that is partially renewable.* (i) The number of gallon-RINs that shall be generated for a given batch of partially renewable transportation fuel shall be equal to a volume calculated according to the following formula:

$V_{RIN} = EV * V_s * FE_R/(FE_R + FE_F)$

Where:

V_{RIN} = RIN volume, in gallons, for use in determining the number of gallon-RINs that shall be generated.
EV = Equivalence value for the renewable fuel per § 80.1415.
V_s = Standardized volume of the batch of renewable fuel at 60 °F, in gallons, calculated in accordance with paragraph (d)(10) of this section.
FE_R = Feedstock energy from renewable biomass used to make the transportation fuel, in Btu.
FE_F = Feedstock energy from fossil fuel used to make the transportation fuel, in Btu.

(ii) The value of FE for use in paragraph (d)(6)(i) of this section shall be calculated from the following formula:

$FE = M * CF * E$

Where:

FE = Feedstock energy, in Btu.
M = Mass of feedstock, in pounds.
CF = Converted Fraction in annual average mass percent, representing that portion of the feedstock that is estimated to be converted into transportation fuel by the producer.
E = Energy content of the fuel precursor fraction for the feedstock, in annual average Btu/lb.

(iii) The D code that shall be used in the RINs generated to represent partially renewable transportation fuel shall be the D code specified in Table 1 to this section which corresponds to the pathway that describes a producer's operations. In determining the appropriate pathway, the contribution of fossil fuel feedstocks to the production of partially renewable fuel shall be ignored.

(7) *Producers without an applicable pathway.* (i) If none of the pathways described in Table 1 to this section apply to a producer's operations, a party generating a RIN may nevertheless use a pathway in Table 1 to this section if EPA allows the use of a temporary D code pursuant to § 80.1416(c).

(ii) If none of the pathways described in Table 1 to this section apply to a producer's operations and the party generating the RIN does not qualify to use a temporary D code according to the provisions of § 80.1416(c), the party must generate RINs if the fuel from its facility qualifies for grandfathering as provided in § 80.1403.

(A) The number of gallon-RINs that shall be generated for a given batch of grandfathered renewable fuel shall be equal to a volume calculated according to the following formula:

$V_{RIN} = EV * V_s$

Where:

V_{RIN} = RIN volume, in gallons, for use in determining the number of gallon-RINs that shall be generated.
EV = Equivalence value for the renewable fuel per § 80.1415.
V_s = Standardized volume of the batch of renewable fuel at 60°F, in gallons, calculated in accordance with paragraph (d)(10) of this section.

(B) A D code of 4 shall be used in the RINs generated under paragraph (d)(7)(ii)(A) of this section.

(8) *Provisions for importers of renewable fuel.* (i) The number of gallon-RINs that shall be generated for a given batch of renewable fuel shall be equal to a volume calculated according to the following formula:

$V_{RIN} = EV * V_s$

Where:

V_{RIN} = RIN volume, in gallons, for use in determining the number of gallon-RINs that shall be generated.
EV = Equivalence value for the renewable fuel per § 80.1415.
V_s = Standardized volume of the batch of renewable fuel at 60 °F, in gallons, calculated in accordance with paragraph (d)(10) of this section.

(ii) The D code that shall be used in the RINs generated by an importer of renewable fuel shall be determined from information provided by the foreign producer specifying the applicable pathway or pathways for the renewable fuel and the provisions of this paragraph (d).

(9) Multiple gallon-RINs generated to represent a given volume of renewable fuel can be represented by a single batch-RIN through the appropriate designation of the RIN volume codes SSSSSSSS and EEEEEEEE.

(i) The value of SSSSSSSS in the batch-RIN shall be 00000001 to represent the first gallon-RIN associated with the volume of renewable fuel.

(ii) The value of EEEEEEEE in the batch-RIN shall represent the last gallon-RIN associated with the volume of renewable fuel, based on the RIN volume determined pursuant to paragraph (d)(4) of this section.

(10) *Standardization of volumes.* In determining the standardized volume of a batch of renewable fuel for purposes of generating RINs under this paragraph (d), the batch volumes shall be adjusted to a standard temperature of 60 °F.

(i) For ethanol, the following formula shall be used:

$V_{s,e} = V_{a,e} * (-0.0006301 * T + 1.0378)$

Where:

$V_{s,e}$ = Standardized volume of ethanol at 60 °F, in gallons.
$V_{a,e}$ = Actual volume of ethanol, in gallons.
T = Actual temperature of the batch, in °F.

(ii) For biodiesel (mono-alkyl esters), the following formula shall be used:

$V_{s,b} = V_{a,b} * (-0.0008008 * T + 1.0480)$

Where:

$V_{s,b}$ = Standardized volume of biodiesel at 60 °F, in gallons.
$V_{a,b}$ = Actual volume of biodiesel, in gallons.
T = Actual temperature of the batch, in °F.

(iii) For other renewable fuels, an appropriate formula commonly accepted by the industry shall be used to standardize the actual volume to 60 °F. Formulas used must be reported to EPA, and may be reviewed for appropriateness.

(11)(i) A party is prohibited from generating RINs for a volume of fuel that it produces if:

(A) The fuel has been produced from a chemical conversion process that uses another renewable fuel as a feedstock, and the renewable fuel used as a feedstock was produced by another party; or

(B) The fuel is not produced from renewable biomass.

(ii) Parties who produce renewable fuel made from a feedstock which itself was a renewable fuel with RINs, shall assign the original RINs to the new renewable fuel.

(e) *Assignment of RINs to batches.* (1) The producer or importer of renewable fuel must assign all RINs generated to volumes of renewable fuel.

(2) A RIN is assigned to a volume of renewable fuel when ownership of the RIN is transferred along with the transfer of ownership of the volume of renewable fuel, pursuant to § 80.1428(a).

(3) All assigned RINs shall have a K code value of 1.

(4) Any RINs generated but not assigned to a volume of renewable fuel must be counted with assigned RINs in

the quarterly RIN and volume inventory balance check calculation required in § 80.1428.

§ 80.1427 How are RINs used to demonstrate compliance?

(a) *Renewable Volume Obligations.* (1) Except as specified in paragraph (b) of this section or § 80.1455, each party that is obligated to meet the Renewable Volume Obligations under § 80.1407, or each party that is an exporter of renewable fuels that is obligated to meet Renewable Volume Obligations under § 80.1430, must demonstrate pursuant to § 80.1452(a)(1) that it owns sufficient RINs to satisfy the following equations:

(i) *Cellulosic biofuel.*

$$(\Sigma RINNUM)_{CB,i} + (\Sigma RINNUM)_{CB,i-1} = RVO_{CB,i}$$

Where:

$(\Sigma RINNUM)_{CB,i}$ = Sum of all owned gallon-RINs that are valid for use in complying with the cellulosic biofuel RVO, were generated in year i, and are being applied towards the $RVO_{CB,i}$, in gallons.

$(\Sigma RINNUM)_{CB,i-1}$ = Sum of all owned gallon-RINs that are valid for use in complying with the cellulosic biofuel RVO, were generated in year i − 1, and are being applied towards the $RVO_{CB,i}$, in gallons.

$RVO_{CB,i}$ = The Renewable Volume Obligation for cellulosic biofuel for the obligated party or renewable fuel exporter for calendar year i, in gallons, pursuant to § 80.1407 or § 80.1430.

(ii) *Biomass-based diesel.*

$$(\Sigma RINNUM)_{BBD,i} + (\Sigma RINNUM)_{BBD,i-1} = RVO_{BBD,i}$$

Where:

$(\Sigma RINNUM)_{BBD,i}$ = Sum of all owned gallon-RINs that are valid for use in complying with the biomass-based diesel RVO, were generated in year i, and are being applied towards the $RVO_{BBD,i}$, in gallons.

$(\Sigma RINNUM)_{BBD,i-1}$ = Sum of all owned gallon-RINs that are valid for use in complying with the biomass-based diesel RVO, were generated in year i − 1, and are being applied towards the $RVO_{BBD,i}$, in gallons.

$RVO_{BBD,i}$ = The Renewable Volume Obligation for biomass-based diesel for the obligated party or renewable fuel exporter for calendar year i after 2010, in gallons, pursuant to § 80.1407 or § 80.1430.

(iii) *Advanced biofuel.*

$$(\Sigma RINNUM)_{AB,i} + (\Sigma RINNUM)_{AB,i-1} = RVO_{AB,i}$$

Where:

$(\Sigma RINNUM)_{AB,i}$ = Sum of all owned gallon-RINs that are valid for use in complying with the advanced biofuel RVO, were generated in year i, and are being applied towards the $RVO_{AB,i}$, in gallons.

$(\Sigma RINNUM)_{AB,i-1}$ = Sum of all owned gallon-RINs that are valid for use in complying with the advanced biofuel RVO, were generated in year i − 1, and are being applied towards the $RVO_{AB,i}$, in gallons.

$RVO_{AB,i}$ = The Renewable Volume Obligation for advanced biofuel for the obligated party or renewable fuel exporter for calendar year i, in gallons, pursuant to § 80.1407 or § 80.1430.

(iv) *Renewable fuel.*

$$(\Sigma RINNUM)_{RF,i} + (\Sigma RINNUM)_{RF,i-1} = RVO_{RF,i}$$

Where:

$(\Sigma RINNUM)_{RF,i}$ = Sum of all owned gallon-RINs that are valid for use in complying with the renewable fuel RVO, were generated in year i, and are being applied towards the $RVO_{RF,i}$, in gallons.

$(\Sigma RINNUM)_{RF,i-1}$ = Sum of all owned gallon-RINs that are valid for use in complying with the renewable fuel RVO, were generated in year i − 1, and are being applied towards the $RVO_{RF,i}$, in gallons.

$RVO_{RF,i}$ = The Renewable Volume Obligation for renewable fuel for the obligated party or renewable fuel exporter for calendar year i, in gallons, pursuant to § 80.1407 or § 80.1430.

(2) Except as described in paragraph (a)(3) of this section, RINs that are valid for use in complying with each Renewable Volume Obligation are determined by their D codes.

(i) RINs with a D code of 1 are valid for compliance with the cellulosic biofuel RVO.

(ii) RINs with a D code of 2 are valid for compliance with the biomass-based diesel RVO.

(iii) RINs with a D code of 1, 2, or 3 are valid for compliance with the advanced biofuel RVO.

(iv) RINs with a D code of 1, 2, 3, or 4 are valid for compliance with the renewable fuel RVO.

(3) For purposes of demonstrating compliance for calendar year 2010, RINs generated in 2009 pursuant to § 80.1126 that are not used for compliance purposes for calendar year 2009 may be used for compliance in 2010, insofar as permissible pursuant to paragraphs (a)(5) and (a)(7)(iv) of this section, as follows:

(i) A 2009 RIN with an RR code of 15 or 17 is deemed equivalent to a RIN generated pursuant to § 80.1426 having a D code of 2.

(ii) A 2009 RIN with a D code of 1 is deemed equivalent to a RIN generated pursuant to § 80.1426 having a D code of 1.

(iii) All other 2009 RINs are deemed equivalent to RINs generated pursuant to § 80.1426 having D codes of 4.

(iv) A 2009 RIN that is retired pursuant to § 80.1129(e) because the associated volume of fuel is not used as motor vehicle fuel may be reinstated pursuant to § 80.1429(f)(1).

(4) A party may use the same RIN to demonstrate compliance with more than one RVO so long as it is valid for compliance with all RVOs to which it is applied.

(5) Except as provided in paragraph (a)(7)(iv) of this section, the value of $(\Sigma RINNUM)_{i-1}$ may not exceed values determined by the following inequalities:

$$(\Sigma RINNUM)_{CB,i-1} \leq 0.20 * RVO_{CB,i}$$

$$(\Sigma RINNUM)_{BBD,i-1} \leq 0.20 * RVO_{BBD,i}$$

$$(\Sigma RINNUM)_{AB,i-1} \leq 0.20 * RVO_{AB,i}$$

$$(\Sigma RINNUM)_{RF,i-1} \leq 0.20 * RVO_{RF,i}$$

(6) Except as provided in paragraphs (a)(7)(ii) and (iii) of this section, RINs may only be used to demonstrate compliance with the RVOs for the calendar year in which they were generated or the following calendar year. RINs used to demonstrate compliance in one year cannot be used to demonstrate compliance in any other year.

(7) *Biomass-based diesel in 2010.* (i) Prior to determining compliance with the 2010 biomass-based diesel RVO, obligated parties may reduce the value of $RVO_{BBD,2010}$ by an amount equal to the sum of all 2008 and 2009 RINs used for compliance purposes for calendar year 2009 which have an RR code of 15 or 17.

(ii) For calendar year 2010 only, the following equation shall be used to determine compliance with the biomass-based diesel RVO instead of the equation in paragraph (a)(1)(ii) of this section:

$$(\Sigma RINNUM)_{BBD,2010} + (\Sigma RINNUM)_{BBD,2009} + (\Sigma RINNUM)_{BBD,2008} = RVO_{BBD,2010}$$

Where:

$(\Sigma RINNUM)_{BBD,2010}$ = Sum of all owned gallon-RINs that are valid for use in complying with the biomass-based diesel RVO, were generated in year 2010, and are being applied towards the $RVO_{BBD,2010}$, in gallons.

$(\Sigma RINNUM)_{BBD,2009}$ = Sum of all owned gallon-RINs that are valid for use in complying with the biomass-based diesel RVO, were generated in year 2009, have not previously been used for compliance purposes, and are being applied towards the $RVO_{BBD,2010}$, in gallons.

$(\Sigma RINNUM)_{BBD,2008}$ = Sum of all owned gallon-RINs that are valid for use in complying with the biomass-based diesel RVO, were generated in year 2008, have not previously been used for compliance purposes, and are being applied towards the $RVO_{BBD,2010}$, in gallons.

$RVO_{BBD,2010}$ = The Renewable Volume Obligation for biomass-based diesel for the obligated party or renewable fuel exporter for calendar year 2010, in gallons, pursuant to § 80.1407 or § 80.1430, as adjusted by paragraph (a)(7)(i) of this section.

(iii) RINs generated in 2008 or 2009 which have not been used for compliance purposes for calendar years 2008 or 2009 and which have an RR code of 15 or 17 may be used to demonstrate compliance with the 2010 biomass-based diesel RVO.

(iv) For compliance with the biomass-based diesel RVO in calendar year 2010 only, the values of $(\Sigma RINNUM)_{2008}$ and $(\Sigma RINNUM)_{2009}$ may not exceed values determined by both of the following inequalities:

$$(\Sigma RINNUM)_{BBD,2008} \leq 0.087 * RVO_{BBD,2010}$$

$$(\Sigma RINNUM)_{BBD,2008} + (\Sigma RINNUM)_{BBD,2009} \leq 0.20 * RVO_{BBD,2010}$$

(8) A party may only use a RIN for purposes of meeting the requirements of paragraph (a)(1) of this section if that RIN is a separated RIN with a K code of 2 obtained in accordance with §§ 80.1428 and 80.1429.

(9) The number of gallon-RINs associated with a given batch-RIN that can be used for compliance with the RVOs shall be calculated from the following formula:

$$RINNUM = EEEEEEEE - SSSSSSSS + 1$$

Where:

RINNUM = Number of gallon-RINs associated with a batch-RIN, where each gallon-RIN represents one gallon of renewable fuel for compliance purposes.

EEEEEEEE = Batch-RIN component identifying the last gallon-RIN associated with the batch-RIN.

SSSSSSSS = Batch-RIN component identifying the first gallon-RIN associated with the batch-RIN.

(b) *Deficit carryovers.* (1) An obligated party or an exporter of renewable fuel that fails to meet the requirements of paragraph (a)(1) or (a)(5) of this section for calendar year i is permitted to carry a deficit into year i+1 under the following conditions:

(i) The party did not carry a deficit into calendar year i from calendar year i−1 for the same RVO.

(ii) The party subsequently meets the requirements of paragraph (a)(1) of this section for calendar year i+1 and carries no deficit into year i+2 for the same RVO.

(iii) For compliance with the biomass-based diesel RVO in calendar year 2011, the deficit which is carried over from 2010 is no larger than 57% of the party's 2010 biomass-based diesel RVO as determined prior to any adjustment applied pursuant to paragraph (a)(7)(i) of this section.

(2) A deficit is calculated according to the following formula:

$$D_i = RVO_i - [(\Sigma RINNUM)_i + (\Sigma RINNUM)_{i-1}]$$

Where:

D_i = The deficit, in gallons, generated in calendar year i that must be carried over to year i+1 if allowed to do so pursuant to paragraph (b)(1) of this section.

RVO_i = The Renewable Volume Obligation for the obligated party or renewable fuel exporter for calendar year i, in gallons.

$(\Sigma RINNUM)_i$ = Sum of all acquired gallon-RINs that were generated in year i and are being applied towards the RVO_i, in gallons.

$(\Sigma RINNUM)_{i-1}$ = Sum of all acquired gallon-RINs that were generated in year i-1 and are being applied towards the RVO_i, in gallons.

§ 80.1428 General requirements for RIN distribution.

(a) *RINs assigned to volumes of renewable fuel and RINs generated, but not assigned.* (1) *Definitions.* (i) *Assigned RIN,* for the purposes of this subpart, means a RIN assigned to a volume of renewable fuel pursuant to § 80.1426(e) with a K code of 1.

(ii) *RINS generated, but not assigned* are those RINs that have been generated pursuant to 80.1426(a), but have not been assigned to a volume of renewable fuel pursuant to 80.1426(e).

(2) Except as provided in § 80.1429, no party can separate a RIN that has been assigned to a batch pursuant to § 80.1426(e).

(3) An assigned RIN cannot be transferred to another party without simultaneously transferring a volume of renewable fuel to that same party.

(4) No more than 2.5 assigned gallon-RINs with a K code of 1 can be transferred to another party with every gallon of renewable fuel transferred to that same party.

(5)(i) On each of the dates listed in paragraph (a)(5)(ii) of this section in any calendar year, the following equation must be satisfied for assigned RINs and volumes of renewable fuel owned by a party:

$$\Sigma(RIN)_D \leq \Sigma(V_{si} * 2.5)_D$$

Where:

D = Applicable date.

$\Sigma(RIN)_D$ = Sum of all assigned gallon-RINs with a K code of 1 and all RINs generated, but not assigned that are owned on date D.

$(V_{si})_D$ = Volume i of renewable fuel owned on date D, standardized to 60 °F, in gallons.

$\Sigma(V_{si} * 2.5)_D$ = Sum of all volumes of renewable fuel owned on date D, multiplied by an equivalence value of 2.5.

(ii) The applicable dates are March 31, June 30, September 30, and December 31.

(6) Any transfer of ownership of assigned RINs must be documented on product transfer documents generated pursuant to § 80.1453.

(i) The RIN must be recorded on the product transfer document used to transfer ownership of the volume of renewable fuel to another party; or

(ii) The RIN must be recorded on a separate product transfer document transferred to the same party on the same day as the product transfer document used to transfer ownership of the volume of renewable fuel.

(b) *RINs separated from volumes of renewable fuel.* (1) *Separated RIN,* for the purposes of this subpart, means a RIN with a K code of 2 that has been separated from a volume of renewable fuel pursuant to § 80.1429.

(2) Any party that has registered pursuant to § 80.1450 can hold title to a separated RIN.

(3) Separated RINs can be transferred from one party to another any number of times.

(c) *RIN expiration.* A RIN is valid for compliance during the year in which it was generated, or the following year. Any RIN that is not used for compliance purposes during the year that it was generated, or during the following year, will be considered an expired RIN. Pursuant to § 80.1431(a)(3), an expired RIN that is used for compliance will be considered an invalid RIN.

(d) Any batch-RIN can be divided by its owner into multiple batch-RINs, each representing a smaller number of gallon-RINs, if all of the following conditions are met:

(1) All RIN components other than SSSSSSSS and EEEEEEEE are identical for the original parent and newly formed daughter RINs.

(2) The sum of the gallon-RINs associated with the multiple daughter batch-RINs is equal to the gallon-RINs associated with the parent batch-RIN.

§ 80.1429 Requirements for separating RINs from volumes of renewable fuel.

(a)(1) Separation of a RIN from a volume of renewable fuel means termination of the assignment of the RIN to a volume of renewable fuel.

(2) RINs that have been separated from volumes of renewable fuel become separated RINs subject to the provisions of § 80.1428(b).

(b) A RIN that is assigned to a volume of renewable fuel is separated from that volume only under one of the following conditions:

(1) Except as provided in paragraph (b)(6) of this section, a party that is an obligated party according to § 80.1406 must separate any RINs that have been assigned to a volume of renewable fuel if they own that volume.

(2) Except as provided in paragraph (b)(5) of this section, any party that owns a volume of renewable fuel must separate any RINs that have been assigned to that volume once the volume is blended with gasoline or diesel to produce a transportation fuel,

home heating oil, or jet fuel. A party may separate up to 2.5 RINs per gallon of renewable fuel.

(3) Any party that exports a volume of renewable fuel must separate any RINs that have been assigned to the exported volume.

(4) Any party that produces, imports, owns, sells, or uses a volume of neat renewable fuel, or a blend of renewable fuel and diesel fuel, must separate any RINs that have been assigned to that volume of neat renewable fuel or that blend if:

(i) The party designates the neat renewable fuel or blend as transportation fuel, home heating oil, or jet fuel: and

(ii) The neat renewable fuel or blend is used without further blending, in the designated form, as transportation fuel, home heating oil, or jet fuel.

(5) RINs assigned to a volume of biodiesel (mono-alkyl ester) can only be separated from that volume pursuant to paragraph (b)(2) of this section if such biodiesel is blended into diesel fuel at a concentration of 80 volume percent biodiesel (mono-alkyl ester) or less.

(i) This paragraph (b)(5) shall not apply to obligated parties or exporters of renewable fuel.

(ii) This paragraph (b)(5) shall not apply to parties meeting the requirements of paragraph (b)(4) of this section.

(6) For RINs that an obligated party generates for renewable fuel that has not been blended into gasoline or diesel to produce a transportation fuel, the obligated party can only separate such RINs from volumes of renewable fuel if the number of gallon-RINs separated in a calendar year is less than or equal to a limit set as follows:

(i) For RINs with a D code of 1, the limit shall be equal to RVO_{CB}.

(ii) For RINs with a D code of 2, the limit shall be equal to RVO_{BBD}.

(iii) For RINs with a D code of 3, the limit shall be equal to RVO_{AB} — RVO_{CB}—RVO_{BBD}.

(iv) For RINs with a D code of 4, the limit shall be equal to RVO_{RF} — RVO_{AB}.

(7) For a party that has received a small refinery exemption under § 80.1441 or a small refiner exemption under § 80.1442, and is not otherwise an obligated party, during the period of time that the small refinery or small refiner exemptions are in effect, the party may only separate RINs that have been assigned to volumes of renewable fuel that the party blends into gasoline or diesel to produce transportation fuel, or that the party used as home heating oil or jet fuel.

(c) The party responsible for separating a RIN from a volume of renewable fuel shall change the K code in the RIN from a value of 1 to a value of 2 prior to transferring the RIN to any other party.

(d) Upon and after separation of a RIN from its associated volume of renewable fuel, the separated RIN must be accompanied by documentation when transferred.

(1) When transferred, the separated RIN shall appear on documentation that includes all the following information:

(i) The name and address of the transferor and transferee.

(ii) The transferor's and transferee's EPA company registration numbers.

(iii) The date of the transfer.

(iv) A list of separated RINs transferred.

(2) [Reserved]

(e) Upon and after separation of a RIN from its associated volume of renewable fuel, product transfer documents used to transfer ownership of the volume must continue to meet the requirements of § 80.1453(a)(5)(iii).

(f) Any party that uses a renewable fuel in a commercial or industrial boiler or ocean-going vessel (as defined in § 80.1401), or designates a renewable fuel for use in a boiler or ocean-going vessel, must retire any RINs received with that renewable fuel and report the retired RINs in the applicable reports under § 80.1452. Any 2009 RINs retired pursuant to § 80.1129(e) may be reinstated by the retiring party for sale or use to demonstrate compliance with a 2010 RVO.

§ 80.1430 Requirements for exporters of renewable fuels.

(a) Any party that owns any amount of renewable fuel, whether in its neat form or blended with gasoline or diesel, that is exported from any of the regions described in § 80.1426(a) shall acquire sufficient RINs to offset all applicable Renewable Volume Obligations representing the exported renewable fuel.

(b) *Renewable Volume Obligations.* An exporter of renewable fuel shall determine its Renewable Volume Obligations from the volumes of the renewable fuel exported.

(1) For exported volumes of biodiesel (mono-alkyl ester) or non-ester renewable diesel, a renewable fuel exporter's Renewable Volume Obligation for biomass-based diesel shall be calculated according to the following formula:

$$RVO_{BBD,i} = \Sigma(VOL_k * EV_k)_i + D_{BBD,i-1}$$

Where:

$RVO_{BBD,i}$ = The Renewable Volume Obligation for biomass-based diesel for the exporter for calendar year i, in gallons.

k = A discrete volume of biodiesel (mono-alkyl ester) or non-ester renewable diesel fuel.

VOL_k = The standardized volume of discrete volume k of exported biodiesel (mono-alkyl ester) or non-ester renewable diesel, in gallons, calculated in accordance with § 80.1426(d)(10).

EV_k = The equivalence value associated with discrete volume k.

Σ = Sum involving all volumes of biodiesel (mono-alkyl ester) or non-ester renewable diesel exported.

$D_{BBD,i-1}$ = Deficit carryover from the previous year for biomass-based diesel, in gallons.

(2) For exported volumes of all renewable fuels, a renewable fuel exporter's Renewable Volume Obligation for total renewable fuel shall be calculated according to the following formula:

$$RVO_{RF,i} = \Sigma(VOL_k * EV_k)_i + D_{RF,i-1}$$

Where:

$RVO_{RF,i}$ = The Renewable Volume Obligation for renewable fuel for the exporter for calendar year i, in gallons of renewable fuel.

k = A discrete volume of renewable fuel.

VOL_k = The standardized volume of discrete volume k of exported renewable fuel, in gallons, calculated in accordance with § 80.1426(d)(10).

EV_k = The equivalence value associated with discrete volume k.

Σ = Sum involving all volumes of renewable fuel exported.

$D_{RF,i-1}$ = Deficit carryover from the previous year for renewable fuel, in gallons.

(3)(i) If the equivalence value for a volume of renewable fuel can be determined pursuant to § 80.1415 based on its composition, then the appropriate equivalence value shall be used in the calculation of the exporter's Renewable Volume Obligations.

(ii) If the equivalence value for a volume of renewable fuel cannot be determined, the value of EV_k shall be 1.0.

(c) Each exporter of renewable fuel must demonstrate compliance with its RVOs using RINs it has acquired, pursuant to § 80.1427.

§ 80.1431 Treatment of invalid RINs.

(a) *Invalid RINs.* An invalid RIN is a RIN that is any of the following:

(1) Is a duplicate of a valid RIN.

(2) Was based on volumes that have not been standardized to 60 °F.

(3) Has expired, except as provided in § 80.1428(c).

(4) Was based on an incorrect equivalence value.

(5) Is deemed invalid under § 80.1467(g).

(6) Does not represent renewable fuel as defined in § 80.1401.

(7) Was assigned an incorrect ''D'' code value under § 80.1426(d)(3) for the associated volume of fuel.

(8) In the event that the same RIN is transferred to two or more parties, all such RINs are deemed invalid, unless EPA in its sole discretion determines that some portion of these RINs is valid.

(9) Was otherwise improperly generated.

(b) In the case of RINs that are invalid, the following provisions apply:

(1) Upon determination by any party that RINs owned are invalid, the party must adjust its records, reports, and compliance calculations in which the invalid RINs were used as necessary to reflect the deletion of the invalid RINs. The party must retire the invalid RINs in the applicable RIN transaction reports under § 80.1452(c)(2) for the quarter in which the RINs were determined to be invalid.

(2) Invalid RINs cannot be used to achieve compliance with the Renewable Volume Obligations of an obligated party or exporter, regardless of the party's good faith belief that the RINs were valid at the time they were acquired.

(3) Any valid RINs remaining after deleting invalid RINs must first be applied to correct the transfer of invalid RINs to another party before applying the valid RINs to meet the party's Renewable Volume Obligations at the end of the compliance year.

§ 80.1432 Reported spillage or disposal of renewable fuel.

(a) A reported spillage or disposal under this subpart means a spillage or disposal of renewable fuel associated with a requirement by a federal, state, or local authority to report the spillage or disposal.

(b) Except as provided in paragraph (c) of this section, in the event of a reported spillage or disposal of any volume of renewable fuel, the owner of the renewable fuel must retire a number of RINs corresponding to the volume of spilled or disposed of renewable fuel multiplied by its equivalence value.

(1) If the equivalence value for the spilled or disposed of volume may be determined pursuant to § 80.1415 based on its composition, then the appropriate equivalence value shall be used.

(2) If the equivalence value for a spilled or disposed of volume of renewable fuel cannot be determined, the equivalence value shall be 1.0.

(c) If the owner of a volume of renewable fuel that is spilled or disposed of and reported establishes that no RINs were generated to represent the volume, then no RINs shall be retired.

(d) A RIN that is retired under paragraph (b) of this section:

(1) Must be reported as a retired RIN in the applicable reports under § 80.1452.

(2) May not be transferred to another party or used by any obligated party to demonstrate compliance with the party's Renewable Volume Obligations.

§§ 80.1433–80.1439 [Reserved]

§ 80.1440 What are the provisions for blenders who handle and blend less than 125,000 gallons of renewable fuel per year?

(a) Renewable fuel blenders who handle and blend less than 125,000 gallons of renewable fuel per year, and who do not have Renewable Volume Obligations, are permitted to delegate their RIN-related responsibilities to the party directly upstream of them who supplied the renewable fuel for blending.

(b) The RIN-related responsibilities that may be delegated directly upstream include all the following:

(1) The RIN separation requirements of § 80.1429.

(2) The recordkeeping requirements of § 80.1451.

(3) The reporting requirements of § 80.1452.

(4) The attest engagement requirements of § 80.1464.

(c) For upstream delegation of RIN-related responsibilities, both parties must agree on the delegation, and a quarterly written statement signed by both parties must be included with the reporting party's reports under § 80.1452.

(1) If EPA finds that a renewable fuel blender improperly delegated its RIN-related responsibilities under this subpart M, the blender will be held accountable for any RINs separated and will be subject to all RIN-related responsibilities under this subpart.

(2) [Reserved]

(d) Renewable fuel blenders who handle and blend less than 125,000 gallons of renewable fuel per year and who do not opt to delegate their RIN-related responsibilities will be subject to all requirements stated in paragraph (b) of this section, and all other applicable requirements of this subpart M.

§ 80.1441 Small refinery exemption.

(a)(1) Transportation fuel produced at a refinery by a refiner, or foreign refiner (as defined at § 80.1465(a)), is exempt through December 31, 2010 from the renewable fuel standards of § 80.1405; and the refinery, or foreign refinery, is exempt from the requirements that apply to obligated parties under this subpart M if that refinery meets the definition of a small refinery under § 80.1401 for calendar year 2006.

(2) This exemption shall apply unless a refiner chooses to waive this exemption (as described in paragraph (f) of this section), or the exemption is extended (as described in paragraph (e) of this section).

(3) For the purposes of this section, the term ''refiner'' shall include foreign refiners.

(4) This exemption shall only apply to refineries that process crude oil through refinery processing units.

(5) The small refinery exemption is effective immediately, except as specified in paragraph (b)(3) of this section.

(b)(1) A refiner owning a small refinery must submit a verification letter to EPA containing all of the following information:

(i) The annual average aggregate daily crude oil throughput for the period January 1, 2006 through December 31, 2006 (as determined by dividing the aggregate throughput for the calendar year by the number 365).

(ii) A letter signed by the president, chief operating or chief executive officer of the company, or his/her designee, stating that the information contained in the letter is true to the best of his/her knowledge, and that the refinery was small as of December 31, 2006.

(iii) Name, address, phone number, facsimile number, and e-mail address of a corporate contact person.

(2) Verification letters must be submitted by January 1, 2010 to one of the addresses listed in paragraph (h) of this section.

(3) For foreign refiners the small refinery exemption shall be effective upon approval, by EPA, of a small refinery application. The application must contain all of the elements required for small refinery verification letters (as specified in paragraph (b)(1) of this section), must satisfy the provisions of § 80.1465(f) through (h) and (o), and must be submitted by January 1, 2010 to one of the addresses listed in paragraph (h) of this section.

(4) Small refinery verification letters are not required for those refiners who have already submitted a verification letter under subpart K of this Part 80.

(c) If EPA finds that a refiner provided false or inaccurate information regarding a refinery's crude throughput (pursuant to paragraph (b)(1)(i) of this section) in its small refinery verification letter, the exemption will be void as of the effective date of these regulations.

(d) If a refiner is complying on an aggregate basis for multiple refineries, any such refiner may exclude from the calculation of its Renewable Volume Obligations (under § 80.1407) transportation fuel from any refinery receiving the small refinery exemption under paragraph (a) of this section.

(e)(1) The exemption period in paragraph (a) of this section shall be extended by the Administrator for a period of not less than two additional years if a study by the Secretary of Energy determines that compliance with the requirements of this subpart would impose a disproportionate economic hardship on a small refinery.

(2) A refiner may petition the Administrator for an extension of its small refinery exemption, based on disproportionate economic hardship, at any time.

(i) A petition for an extension of the small refinery exemption must specify the factors that demonstrate a disproportionate economic hardship and must provide a detailed discussion regarding the hardship the refinery would face in producing transportation fuel meeting the requirements of § 80.1405 and the date the refiner anticipates that compliance with the requirements can reasonably be achieved at the small refinery.

(ii) The Administrator shall act on such a petition not later than 90 days after the date of receipt of the petition.

(f) At any time, a refiner with an approved small refinery exemption under paragraph (a) of this section may waive that exemption upon notification to EPA.

(1) A refiner's notice to EPA that it intends to waive its small refinery exemption must be received by November 1 to be effective in the next compliance year.

(2) The waiver will be effective beginning on January 1 of the following calendar year, at which point the gasoline produced at that refinery will be subject to the renewable fuels standard of § 80.1405 and all other requirements that apply to obligated parties under this Subpart M.

(3) The waiver must be sent to EPA at one of the addresses listed in paragraph (h) of this section.

(g) A refiner that acquires a refinery from either an approved small refiner (as defined under § 80.1442(a)) or another refiner with an approved small refinery exemption under paragraph (a) of this section shall notify EPA in writing no later than 20 days following the acquisition.

(h) Verification letters under paragraph (b) of this section, petitions for small refinery hardship extensions under paragraph (e) of this section, and small refinery exemption waivers under paragraph (f) of this section shall be sent to one of the following addresses:

(1) *For US mail:* U.S. EPA, Attn: RFS2 Program, 6406J, 1200 Pennsylvania Avenue, NW., Washington, DC 20460.

(2) *For overnight or courier services:* U.S. EPA, Attn: RFS2 Program, 6406J, 1310 L Street, NW, 6th floor, Washington, DC 20005. (202) 343–9038.

§ 80.1442 What are the provisions for small refiners under the RFS program?

(a)(1) To qualify as a small refiner under this section, a refiner must meet all of the following criteria:

(i) The refiner produced transportation fuel at its refineries by processing crude oil through refinery processing units from January 1, 2006 through December 31, 2006.

(ii) The refiner employed an average of no more than 1,500 people, based on the average number of employees for all pay periods for calendar year 2006 for all subsidiary companies, all parent companies, all subsidiaries of the parent companies, and all joint venture partners.

(iii) The refiner had a corporate-average crude oil capacity less than or equal to 155,000 barrels per calendar day (bpcd) for 2006.

(2) For the purposes of this section, the term ''refiner'' shall include foreign refiners.

(b) *Applications for small refiner status.* (1) Applications for small refiner status under this section must be submitted to EPA by January 1, 2010.

(2) Small refiner status applications under this section must include all the following information for the refiner and for all subsidiary companies, all parent companies, all subsidiaries of the parent companies, and all joint venture partners:

(i) A listing of the name and address of each company location where any employee worked for the period January 1, 2006 through December 31, 2006.

(ii) The average number of employees at each location based on the number of employees for each pay period for the period January 1, 2006 through December 31, 2006.

(iii) The type of business activities carried out at each location.

(iv) For joint ventures, the total number of employees includes the combined employee count of all corporate entities in the venture.

(v) For government-owned refiners, the total employee count includes all government employees.

(vi) The total corporate crude oil capacity of each refinery as reported to the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE), for the period January 1, 2006 through December 31, 2006. The information submitted to EIA is presumed to be correct. In cases where a company disagrees with this information, the company may petition EPA with appropriate data to correct the record when the company submits its application.

(vii) A letter signed by the president, chief operating or chief executive officer of the company, or his/her designee, stating that the information contained in the application is true to the best of his/her knowledge.

(viii) Name, address, phone number, facsimile number, and e-mail address of a corporate contact person.

(3) In the case of a refiner who acquires or reactivates a refinery that was shut down or non-operational between January 1, 2005 and January 1, 2006, the information required in paragraph (b)(2) of this section must be provided for the time period since the refiner acquired or reactivated the refinery.

(4) EPA will notify a refiner of its approval or disapproval of the application for small refiner status by letter.

(5) For foreign refiners the small refiner exemption shall be effective upon approval, by EPA, of a small refiner application. The application must contain all of the elements required for small refiner status applications (as specified in paragraph (b)(2) of this section), must satisfy the provisions of § 80.1465(f) through (h) and (o), must demonstrate compliance with the crude oil capacity criterion of paragraph (a)(1)(iii) of this section, and must be submitted by January 1, 2010 to one of the addresses listed in paragraph (i) of this section.

(c) *Small refiner temporary exemption.* (1) Transportation fuel produced by a refiner, or foreign refiner (as defined at § 80.1465(a)), is exempt through December 31, 2010 from the renewable fuel standards of § 80.1405 and the requirements that apply to obligated parties under this subpart if the refiner or foreign refiner meets all of the following criteria:

(i) The refiner produced transportation fuel at its refineries by processing crude oil through refinery processing units from January 1, 2006 through December 31, 2006.

(ii) The refiner employed an average of no more than 1,500 people, based on the average number of employees for all pay periods for calendar year 2006 for all subsidiary companies, all parent companies, all subsidiaries of the parent companies, and all joint venture partners.

(iii) The refiner had a corporate-average crude oil capacity less than or equal to 155,000 barrels per calendar day (bpcd) for 2006.

(2) The small refiner exemption shall apply to an approved small refiner unless that refiner chooses to waive this exemption (as described in paragraph (d) of this section).

(d)(1) A refiner with approved small refiner status may, at any time, waive the small refiner exemption under paragraph (c) of this section upon notification to EPA.

(2) A refiner's notice to EPA that it intends to waive the small refiner exemption must be received by November 1 of a given year in order for the waiver to be effective for the following calendar year. The waiver will be effective beginning on January 1 of the following calendar year, at which point the refiner will be subject to the renewable fuel standards of § 80.1405 and the requirements that apply to obligated parties under this subpart.

(3) The waiver must be sent to EPA at one of the addresses listed in paragraph (j) of this section.

(e) Refiners who qualify as small refiners under this section and subsequently fail to meet all of the qualifying criteria as set out in paragraph (a) of this section are disqualified as small refiners as of the effective date of this subpart, except as provided under paragraphs (d) and (e)(2) of this section.

(1) In the event such disqualification occurs, the refiner shall notify EPA in writing no later than 20 days following the disqualifying event.

(2) Disqualification under this paragraph (e) shall not apply in the case of a merger between two approved small refiners.

(f) If EPA finds that a refiner provided false or inaccurate information in its application for small refiner status under this subpart M, the refiner will be disqualified as a small refiner as of the effective date of this subpart.

(g) Any refiner that acquires a refinery from another refiner with approved small refiner status under paragraph (a) of this section shall notify EPA in writing no later than 20 days following the acquisition.

(h) *Extensions of the small refiner temporary exemption.* (1) A small refiner may apply for an extension of the temporary exemption of paragraph (c)(1) of this section based on a showing of all the following:

(i) Circumstances exist that impose disproportionate economic hardship on the refiner and significantly affect the refiner's ability to comply with the RFS standards.

(ii) The refiner has made best efforts to comply with the requirements of this subpart.

(2) A refiner must apply, and be approved, for small refiner status under this section.

(3) A small refiner's hardship application must include all the following information:

(i) A plan demonstrating how the refiner will comply with the requirements of § 80.1405 (and all other requirements of this subpart applicable to obligated parties), as expeditiously as possible.

(ii) A detailed description of the refinery configuration and operations including, at a minimum, all the following information:

(A) The refinery's total crude capacity.

(B) Total crude capacity of any other refineries owned by the same entity.

(C) Total volume of gasoline and diesel produced at the refinery.

(D) Detailed descriptions of efforts to comply.

(E) Bond rating of the entity that owns the refinery.

(F) Estimated investment needed to comply with the requirements of this subpart.

(4) A small refiner shall notify EPA in writing of any changes to its situation between approval of the extension application and the end of its approved extension period.

(5) EPA may impose reasonable conditions on extensions of the temporary exemption, including reducing the length of such an extension, if conditions or situations change between approval of the application and the end of the approved extension period.

(i) Applications for small refiner status, small refiner exemption waivers, or extensions of the small refiner temporary exemption under this section must be sent to one of the following addresses:

(1) *For US Mail:* U.S. EPA, *Attn:* RFS2 Program, 6406J, 1200 Pennsylvania Avenue, NW., Washington, DC 20460.

(2) *For overnight or courier services:* U.S. EPA, *Attn:* RFS2 Program, 6406J, 1310 L Street, NW., 6th floor, Washington, DC 20005. (202) 343–9038.

§ 80.1443 What are the opt-in provisions for noncontiguous states and territories?

(a) Alaska or a United States territory may petition the Administrator to opt-in to the program requirements of this subpart.

(b) The Administrator will approve the petition if it meets the provisions of paragraphs (c) and (d) of this section.

(c) The petition must be signed by the Governor of the state or his authorized representative (or the equivalent official of the territory).

(d)(1) A petition submitted under this section must be received by EPA by November 1 for the state or territory to be included in the RFS program in the next calendar year.

(2) A petition submitted under this section should be sent to either of the following addresses:

(i) *For US Mail:* U.S. EPA, *Attn:* RFS Program, 6406J, 1200 Pennsylvania Avenue, NW., Washington, DC 20460.

(ii) *For overnight or courier services:* U.S. EPA, *Attn:* RFS Program, 6406J, 1310 L Street, NW., 6th floor, Washington, DC 20005. (202) 343–9038.

(e) Upon approval of the petition by the Administrator:

(1) EPA shall calculate the standards for the following year, including the total gasoline and diesel fuel volume for the state or territory in question.

(2) Beginning on January 1 of the next calendar year, all gasoline and diesel fuel refiners and importers in the state or territory for which a petition has been approved shall be obligated parties as defined in § 80.1406.

(3) Beginning on January 1 of the next calendar year, all renewable fuel producers in the state or territory for which a petition has been approved shall, pursuant to § 80.1426(a)(2), be required to generate RINs and comply with other requirements of this subpart M that are applicable to producers of renewable fuel.

§ 80.1444–80.1448 [Reserved]

§ 80.1449 What are the Production Outlook Report requirements?

(a) A renewable fuel producer or importer, for each of its facilities, must submit all the following information, as applicable, to EPA annually beginning February 28, 2010:

(1) The type, or types, of renewable fuel expected to be produced or imported at each facility owned by the renewable fuel producer or importer.

(2) The volume of each type of renewable fuel expected to be produced or imported at each facility.

(3) The number of RINs expected to be generated by the renewable fuel producer or importer for each type of renewable fuel.

(4) Information about all the following:

(i) Existing and planned production capacity.

(ii) Long-range plans.

(iii) Feedstocks and production processes to be used at each production facility.

(iv) Changes to the facility that would raise or lower emissions of any greenhouse gases from the facility.

(5) For expanded production capacity that is planned or underway at each existing facility, or new production facilities that are planned or underway, information on all the following:

(i) Strategic planning.

(ii) Planning and front-end engineering.

(iii) Detailed engineering and permitting.

(iv) Procurement and construction.

(v) Commissioning and startup.

(6) Whether capital commitments have been made or are projected to be made.

(b) The information listed in paragraph (a) of this section shall include the reporting party's best estimates for the five following calendar years.

(c) Production outlook reports must provide an update of the progress in each of the areas listed in paragraph (a)(5) of this section.

(d) Production outlook reports shall be sent to one of the following addresses:

(1) *For US Mail:* U.S. EPA, Attn: RFS2 Program-Production Outlook Reports, 6406J, 1200 Pennsylvania Avenue, NW., Washington, DC 20460.

(2) *For overnight or courier services:* U.S. EPA, Attn: RFS2 Program-Production Outlook Reports, 6406J, 1310 L Street, NW., 6th floor, Washington, DC 20005. (202) 343–9038.

§ 80.1450 What are the registration requirements under the RFS program?

(a) *Obligated Parties and Exporters.* Any obligated party described in § 80.1406, and any exporter of renewable fuel described in § 80.1430, must provide EPA with the information specified for registration under § 80.76, if such information has not already been provided under the provisions of this part. An obligated party or an exporter of renewable fuel must receive EPA-issued identification numbers prior to engaging in any transaction involving RINs. Registration information must be submitted to EPA by January 1, 2010 or 60 days prior to engaging in any transaction involving RINs, whichever is later.

(b) *Producers.* Except as provided in § 80.1426(b)(1), any foreign or domestic producer of renewable fuel, regardless of whether RINs will be generated for that renewable fuel, must provide EPA the information specified under § 80.76 if such information has not already been provided under the provisions of this part, and must receive EPA-issued company and facility identification numbers prior to generating or assigning any RINs. All the following registration information must be submitted to EPA by January 1, 2010 or 60 days prior to the production of any renewable fuel subject to this subpart, whichever is later:

(1) A description of the types of renewable fuels and co-products produced at the facility and all the following for each product type:

(i) A list of the feedstocks capable of being utilized by the facility.

(ii) A description of the facility's renewable fuel production processes.

(iii) The facility's renewable fuel production capacity.

(iv) A list of the facility's process energy sources.

(v) For a producer of renewable fuel with a facility that commenced construction on or before December 19, 2007 per § 80.1403:

(A) The location of the facility.

(B) Record of costs of additions, replacements, and repairs inclusive of labor costs conducted at the facility since December 19, 2007.

(C) The estimated life of the facility.

(D) A discussion of any economic or technical limitations the facility may have in using a fuel production pathway that will achieve a 20 percent reduction in GHG as compared to baseline fuel.

(2) An independent third party engineering review and written verification of the descriptions made pursuant to paragraph (b)(1) of this section.

(i) The verifications required under this section must be conducted by a licensed Professional Engineer who works in the chemical engineering field and who is licensed by the appropriate state agency.

(ii) To be considered an independent third party under this paragraph (b)(2):

(A) The third party shall not be operated by the renewable fuel producer or any subsidiary or employee of the renewable fuel producer.

(B) The third party shall be free from any interest in the renewable fuel producer's business.

(C) The renewable fuel producer shall be free from any interest in the third party's business.

(D) Use of a third party that is debarred, suspended, or proposed for debarment pursuant to the Government-wide Debarment and Suspension regulations, 40 CFR part 32, or the Debarment, Suspension and Ineligibility provisions of the Federal Acquisition Regulations, 48 CFR, part 9, subpart 9.4, shall be deemed noncompliance with the requirements of this section.

(iii) The independent third party shall retain all records pertaining to the verification required under this section for a period of five years from the date of creation and shall deliver such records to the Administrator upon request.

(iv) The renewable fuel producer must retain records of the review and verification, as required in § 80.1451(b)(7).

(c) *Importers.* Importers of renewable fuel must provide EPA the information specified under § 80.76, if such information has not already been provided under the provisions of this part and must receive an EPA-issued company identification number prior to owning any RINs. Registration information may be submitted to EPA by January 1, 2010 or 60 days prior to engaging in any transaction involving RINs, whichever is later.

(d) *Registration updates.* Except as provided in § 80.1426(b)(1):

(1) Any producer of renewable fuel who makes changes to his facility that will qualify his renewable fuel for a renewable fuel category or D code as defined in § 80.1425(g) that is not reflected in the producer's registration information on file with EPA must update his registration information and submit a copy of an updated independent engineering review at least 60 days prior to producing the new type of renewable fuel.

(2) Any producer of renewable fuel who makes any other changes to a facility not affecting the renewable fuel category for which the producer is registered must update his registration information within 7 days of the change.

(e) *Parties who own RINs or who intend to own RINs.* Any party who owns or intends to own RINs, but who is not covered by paragraphs (a), (b), or (d) of this section, must provide EPA the information specified under § 80.76, if such information has not already been provided under the provisions of this part and must receive an EPA-issued company identification number prior to owning any RINs. Registration information must be submitted to EPA by January 1, 2010 or 60 days prior to engaging in any transaction involving RINs, whichever is later.

(f) Registration shall be on forms, and following policies, established by the Administrator.

§ 80.1451 What are the recordkeeping requirements under the RFS program?

(a) Beginning January 1, 2010, any obligated party (as described at § 80.1406) or exporter of renewable fuel (as described at § 80.1430) must keep all of the following records:

(1) Product transfer documents consistent with § 80.1453 and associated with the obligated party's activity, if any, as transferor or transferee of renewable fuel.

(2) Copies of all reports submitted to EPA under §§ 80.1449 and 80.1452(a).

(3) Records related to each RIN transaction, including all the following:

(i) A list of the RINs owned, purchased, sold, retired, or reinstated.

(ii) The parties involved in each RIN transaction including the transferor, transferee, and any broker or agent.

(iii) The date of the transfer of the RIN(s).

(iv) Additional information related to details of the transaction and its terms.

(4) Records related to the use of RINs (by facility, if applicable) for compliance, including all the following:

(i) Methods and variables used to calculate the Renewable Volume Obligations pursuant to § 80.1407 or § 80.1430.

(ii) List of RINs used to demonstrate compliance.

(iii) Additional information related to details of RIN use for compliance.

(b) Beginning January 1, 2010, any foreign or domestic producer of a renewable fuel as defined in § 80.1401 must keep all of the following records:

(1) Product transfer documents consistent with § 80.1453 and associated with the renewable fuel producer's activity, if any, as transferor or transferee of renewable fuel.

(2) Copies of all reports submitted to EPA under §§ 80.1449 and 80.1452(b).

(3) Records related to the generation and assignment of RINs for each facility, including all of the following:

(i) Batch volume in gallons.

(ii) Batch number.

(iii) RIN as assigned under § 80.1426.

(iv) Identification of batches by renewable category.

(v) Date of production.

(vi) Results of any laboratory analysis of batch chemical composition or physical properties.

(vii) Additional information related to details of RIN generation.

(4) Records related to each RIN transaction, including all of the following:

(i) A list of the RINs owned, purchased, sold, retired, or reinstated.

(ii) The parties involved in each transaction including the transferor, transferee, and any broker or agent.

(iii) The date of the transfer of the RIN(s).

(iv) Additional information related to details of the transaction and its terms.

(5) Records related to the production, importation, ownership, sale or use of any volume of renewable fuel or blend of renewable fuel and gasoline or diesel fuel that any party designates for use as transportation fuel, jet fuel, or home heating oil and the use of the fuel or blend as transportation fuel, jet fuel, or home heating oil without further blending, in the designated form.

(6) Documents associated with feedstock purchases and transfers that identify where the feedstocks were produced and are sufficient to verify that feedstocks used are renewable biomass (as defined in § 80.1401) if RINs are generated, or sufficient to verify that feedstocks used are not renewable biomass if no RINs are generated.

(i) Renewable fuel producers who use planted crops or crop residue from existing agricultural land, or who use planted trees or slash from actively managed tree plantations must keep records that serve as evidence that the land from which the feedstock was obtained was continuously actively managed or fallow, and nonforested, since December 19, 2007. The records must be provided by the feedstock producer and consist of at least one of the following documents: Sales records for planted crops or trees, crop residue, livestock, or slash; purchasing records for fertilizer, weed control, or reseeding, including seeds, seedlings, or other nursery stock; a written management plan for agricultural or silvicultural purposes; documentation of participation in an agricultural, or silvicultural program sponsored by a Federal, state or local government agency; or documentation of land management in accordance with an agricultural or silvicultural product certification program.

(ii) Renewable fuel producers who use any other type of renewable biomass must have written certification from their feedstock supplier that the feedstock qualifies as renewable biomass.

(iii) Renewable fuel producers who do not use renewable biomass must have written certification from their feedstock supplier that the feedstock does not qualify as renewable biomass.

(7) Copies of registration documents required under § 80.1450, including information on fuels and products, feedstocks, facility production processes and capacity, energy sources, and independent third party engineering review.

(c) Beginning January 1, 2010, any importer of a renewable fuel (as defined in § 80.1401) must keep all of the following records:

(1) Product transfer documents consistent with § 80.1453 and associated with the renewable fuel importer's activity, if any, as transferor or transferee of renewable fuel.

(2) Copies of all reports submitted to EPA under §§ 80.1449 and 80.1452(b); however, duplicate records are not required.

(3) Records related to the generation and assignment of RINs for each facility, including all of the following:

(i) Batch volume in gallons.

(ii) Batch number.

(iii) RIN as assigned under § 80.1426.

(iv) Identification of batches by renewable category.

(v) Date of import.

(vi) Results of any laboratory analysis of batch chemical composition or physical properties.

(vii) Additional information related to details of RIN generation.

(4) Records related to each RIN transaction, including all of the following:

(i) A list of the RINs owned, purchased, sold, retired, or reinstated.

(ii) The parties involved in each transaction including the transferor, transferee, and any broker or agent.

(iii) The date of the transfer of the RIN(s).

(iv) Additional information related to details of the transaction and its terms.

(5) Documents associated with feedstock purchases and transfers, sufficient to verify that feedstocks used are renewable biomass (as defined in § 80.1401) if the importer generates RINs.

(6) Documents associated with feedstock purchases and transfers, sufficient to verify that feedstocks used are not renewable biomass as defined in § 80.1401 if the importer does not generate RINs.

(7) Copies of registration documents required under § 80.1450.

(8) Records related to the import of any volume of renewable fuel that the importer designates for use as transportation fuel, jet fuel, or home heating oil.

(d) Beginning January 1, 2010, any production facility with a baseline volume of fuel that is not subject to the 20% GHG threshold, pursuant to § 80.1403(a), must keep all of the following:

(1) Detailed engineering plans for the facility.

(2) Federal, State, and local preconstruction approvals and permitting.

(3) Procurement and construction contracts and agreements.

(4) Records of electricity consumption and energy use.

(5) Records showing costs of additions, replacements, and repairs inclusive of labor costs conducted at the facility since December 19, 2007.

(6) Records estimating the life of the existing facility.

(e) Beginning January 1, 2010, any party, other than those parties covered in paragraphs (a) and (b) of this section, that owns RINs must keep all of the following records:

(1) Product transfer documents consistent with § 80.1453 and associated with the party's activity, if any, as transferor or transferee of renewable fuel.

(2) Copies of all reports submitted to EPA under § 80.1452(c).

(3) Records related to each RIN transaction by renewable fuel category, including all of the following:

(i) A list of the RINs owned, purchased, sold, retired, or reinstated.

(ii) The parties involved in each RIN transaction including the transferor, transferee, and any broker or agent.

(iii) The date of the transfer of the RIN(s).

(iv) Additional information related to details of the transaction and its terms.

(4) Records related to any volume of renewable fuel that the party designated for use as transportation fuel, jet fuel, or home heating oil and from which RINs were separated pursuant to § 80.1429(b)(4).

(f) The records required under paragraphs (a) through (c) of this section and under § 80.1453 shall be kept for five years from the date they were created, except that records related to transactions involving RINs shall be kept for five years from the date of transfer.

(g) The records required under paragraph (d) of this section shall be kept through calendar year 2022.

(h) On request by EPA, the records required under this section and under § 80.1453 must be made available to the Administrator or the Administrator's authorized representative. 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.

(i) The records required in paragraphs (b)(6) and (b)(7) of this section must be provided to the importer of the renewable fuel by any foreign producer not generating RINs for his renewable fuel.

§ 80.1452 What are the reporting requirements under the RFS program?

(a) *Obligated parties and exporters.* Any obligated party described in § 80.1406 or exporter of renewable fuel described in § 80.1430 must submit to EPA reports according to the schedule, and containing all the information, that is set forth in this paragraph (a).

(1) Annual compliance demonstration reports for the previous compliance period shall be submitted on February 28 of each year and shall include all of the following information:

(i) The obligated party's name.

(ii) The EPA company registration number.

(iii) Whether the party is complying on a corporate (aggregate) or facility-by-facility basis.

(iv) The EPA facility registration number, if complying on a facility-by-facility basis.

(v) The production volume of all of the products listed in § 80.1407(c) and (f) for the reporting year.

(vi) The RVOs, as defined in § 80.1427(a) for obligated parties and § 80.1430(b) for exporters of renewable fuel, for the reporting year.

(vii) Any deficit RVOs carried over from the previous year.

(viii) The total current-year RINs by type of renewable fuel, as those fuels are defined in § 80.1401 (i.e., cellulosic biofuel, biomass-based diesel, advanced biofuels, and renewable fuels), used for compliance.

(ix) The total prior-year RINs by renewable fuel type, as those fuels are defined in § 80.1401, used for compliance.

(x) A list of all RINs used for compliance in the reporting year.

(A) For the 2010 reporting year only (January 1—December 31, 2010), a list of all 38-digit RINs used to demonstrate compliance.

(B) Starting January 1, 2011, RINs used to meet compliance will be conveyed via the EPA Moderated Transaction System (EMTS) as set forth in paragraph (e) of this section.

(xi) Any deficit RVO(s) carried into the subsequent year.

(xii) Any additional information that the Administrator may require.

(2) The RIN transaction reports required under paragraph (c)(1) of this section.

(3) The quarterly RIN activity reports required under paragraph (c)(2) of this section.

(4) Reports required under this paragraph (a) must be signed and certified as meeting all the applicable requirements of this subpart by the owner or a responsible corporate officer of the obligated party.

(b) *Renewable fuel producers (domestic and foreign) and importers.* Any domestic producer or importer of renewable fuel, or foreign renewable fuel producer who generates RINs, must submit to EPA reports according to the schedule, and containing all the information, that is set forth in this paragraph (b).

(1)(i) Until December 31, 2010, renewable fuel production reports for each facility owned by the renewable fuel producer or importer shall be submitted monthly, according to the schedule specified in paragraph (d)(1) of this section.

(ii) Starting January 1, 2011, renewable fuel production reports for each facility owned by the renewable fuel producer or importer shall be submitted in accordance with paragraph (e)(2) of this section.

(iii) The renewable fuel production reports shall include all the following information for each batch of renewable fuel produced, where ''batch'' means a discrete quantity of renewable fuel produced and either assigned or not assigned a unique batch-RIN per § 80.1426(b)(2):

(A) The renewable fuel producer's name.

(B) The EPA company registration number.

(C) The EPA facility registration number.

(D) The applicable monthly reporting period.

(E) Whether RINs were generated for each batch according to § 80.1426.

(F) The production date of each batch.

(G) The type of renewable fuel of each batch, as defined in § 80.1401.

(H) Information related to the volume of denaturant and applicable equivalence value of each batch.

(I) The volume of each batch produced.

(J) The process(es) and feedstock(s) used and proportion of renewable volume attributable to each process and feedstock.

(K) The type and volume of co-products produced with each batch of renewable fuel.

(L) In the case that RINs were generated for the batch, a list of the RINs generated and a certification that the feedstock(s) used for each batch meets the definition of renewable biomass as defined in § 80.1401.

(M) In the case that RINs were not generated for the batch, an explanation as to the reason for not generating RINs.

(N) Any additional information the Administrator may require.

(2) The RIN transaction reports required under paragraph (c)(1) of this section.

(3) The quarterly RIN activity reports required under paragraph (c)(2) of this section.

(4) Reports required under this paragraph (b) must be signed and certified as meeting all the applicable requirements of this subpart by the owner or a responsible corporate officer of the renewable fuel producer.

(c) *All RIN-owning parties.* Any party, including any party specified in paragraphs (a) and (b) of this section, that owns RINs during a reporting period, must submit reports to EPA according to the schedule, and containing all the information, that is set forth in this paragraph (c).

(1)(i) Until December 31, 2010, RIN transaction reports listing each RIN transaction shall be submitted monthly according to the schedule in paragraph (d)(1) of this section.

(ii) Starting January 1, 2011, RIN transaction reports listing each RIN transaction shall be submitted in accordance with paragraph (e)(3) of this section.

(iii) Each report required by paragraph (c)(1)(i) of this section shall include all of the following information:

(A) The submitting party's name.

(B) The party's EPA company registration number.

(C) [Reserved]

(D) The applicable monthly reporting period.

(E) Transaction type (i.e., RIN purchase, RIN sale, retired RIN, reinstated 2009 RIN).

(F) Transaction date.

(G) For a RIN purchase or sale, the trading partner's name.

(H) For a RIN purchase or sale, the trading partner's EPA company registration number. For all other transactions, the submitting party's EPA company registration number.

(I) RIN subject to the transaction.

(J) For a RIN purchase or sale, the per gallon RIN price and/or the per gallon renewable price if the RIN price is included.

(K) For a retired RIN, the reason for retiring the RIN (e.g., invalid RIN under § 80.1431, reportable spill under § 80.1432, foreign producer volume correction under § 80.1466(e), renewable fuel used in a boiler or ocean-going vessel under § 80.1429(f), enforcement obligation, or use for compliance (per paragraph (a)(1)(x) of this section), etc.).

(L) Any additional information that the Administrator may require.

(2) Quarterly RIN activity reports shall be submitted to EPA according to the schedule specified in paragraph (d)(2) of this section. Each report shall summarize RIN activities for the reporting period, separately for RINs separated from a renewable fuel volume and the sum of both RINs assigned to a renewable fuel volume and RINs generated, but not assigned to a renewable fuel volume. The quarterly RIN activity reports shall include all of the following information:

(i) The submitting party's name.

(ii) The party's EPA company registration number.

(iii) The number of current-year RINs owned at the start of the month.

(iv) The number of prior-year RINs owned at the start of the month.

(v) The total current-year RINs purchased.

(vi) The total prior-year RINs purchased.

(vii) The total current-year RINs sold.

(viii) The total prior-year RINs sold.

(ix) The total current-year RINs retired.

(x) The total prior-year RINs retired.

(xi) The number of current-year RINs owned at the end of the quarter.

(xii) The number of prior-year RINs owned at the end of the quarter.

(xiii) For parties reporting RIN activity under this paragraph for RINs generated, but not assigned to a renewable fuel volume and/or RINs assigned to a volume of renewable fuel, and the volume of renewable fuel (in gallons) owned at the end of the quarter.

(xiv) The total 2009 retired RINs reinstated.

(xv) Any additional information that the Administrator may require.

(3) All reports required under this paragraph (c) must be signed and certified as meeting all the applicable requirements of this subpart by the RIN owner or a responsible corporate officer of the RIN owner.

(d) *Report submission deadlines.* The submission deadlines for monthly and quarterly reports shall be as follows:

(1) Monthly reports shall be submitted to EPA by the last day of the next calendar month following the compliance period (i.e., the report covering January would be due by February 28th, the report covering February would be due by March 31st, etc.).

(2) Quarterly reports shall be submitted to EPA by the last day of the second month following the compliance period (i.e., the report covering January–March would be due by May 31st, the report covering April–June would be due by August 31st, the report covering July–September would be due by November 30th and the report covering October–December would be due by February 28th).

(e) *EPA Moderated Transaction System (EMTS).* (1) Each party required to report under this section must establish an account with EMTS by October 1, 2010 or sixty (60) days prior to engaging in any transaction involving RINs, whichever is later.

(2) Starting January 1, 2011, each time a domestic producer or importer of renewable fuel, or foreign renewable fuel producer who generates RINs, produces or imports a batch of renewable fuel, all the following information must be submitted to EPA within three (3) business days:

(i) The renewable fuel producer's or importer's name.

(ii) The EPA company registration number.

(iii) The EPA facility registration number.

(iv) Whether RINs were generated for the batch, according to § 80.1426.

(v) The production date of the batch.

(vi) The type of renewable fuel of the batch, as defined in § 80.1401.

(vii) Information related to the volume of denaturant and applicable equivalence value of each batch.

(viii) The volume of the batch.

(ix) The process(es) and feedstock(s) used and proportion of renewable volume attributable to each process and feedstock.

(x) A certification that the feedstock(s) used for each batch meets the definition of renewable biomass as defined in § 80.1401.

(xi) The type and volume of co-products produced with the batch of renewable fuel.

(xii) In the case that RINs were generated for the batch, a list of the RINs generated and a certification that the feedstock(s) used for each batch meets the definition of renewable biomass as defined in § 80.1401.

(xiii) In the case that RINs were not generated for the batch, an explanation as to the reason for not generating RINs.

(xiv) Any additional information the Administrator may require.

(3) Starting January 1, 2011, each time any party engages in a transaction involving RINs, all the following information must be submitted to EPA within three (3) business days:

(i) The submitting party's name.

(ii) The party's EPA company registration number.

(iii) [Reserved]

(iv) The applicable monthly reporting period.

(v) Transaction type (i.e., RIN purchase, RIN sale, retired RIN).

(vi) Transaction date.

(vii) For a RIN purchase or sale, the trading partner's name.

(viii) For a RIN purchase or sale, the trading partner's EPA company registration number. For all other transactions, the submitting party's EPA company registration number.

(ix) RIN subject to the transaction.

(x) For a RIN purchase or sale, the per gallon RIN price and/or the per gallon renewable price if the RIN price is included.

(xi) For a retired RIN, the reason for retiring the RIN (e.g., reportable spill under § 80.1432, foreign producer volume correction under § 80.1466(e), renewable fuel used in a boiler or ocean-going vessel under § 80.1429(f), enforcement obligation, or use for compliance (per paragraph (a)(1)(x) of this section), etc.).

(xii) Any additional information that the Administrator may require.

(f) All reports required under this section shall be submitted on forms and following procedures prescribed by the Administrator.

§ 80.1453 What are the product transfer document (PTD) requirements for the RFS program?

(a) On each occasion when any party transfers ownership of renewable fuels subject to this subpart, the transferor must provide to the transferee documents identifying the renewable fuel and any assigned RINs which include all of the following information, as applicable:

(1) The name and address of the transferor and transferee.

(2) The transferor's and transferee's EPA company registration number.

(3) The volume of renewable fuel that is being transferred.

(4) The date of the transfer.

(5) Whether any RINs are assigned to the volume, as follows:

(i) If the assigned RINs are being transferred on the same PTD used to transfer ownership of the renewable fuel, then the assigned RINs shall be listed on the PTD.

(ii) If the assigned RINs are being transferred on a separate PTD from that which is used to transfer ownership of the renewable fuel, then the PTD which is used to transfer ownership of the renewable fuel shall state the number of gallon-RINs being transferred as well as a unique reference to the PTD which is transferring the assigned RINs.

(iii) If no assigned RINs are being transferred with the renewable fuel, the PTD which is used to transfer ownership of the renewable fuel shall state ''No assigned RINs transferred''.

(iv) If RINs have been separated from the renewable fuel or blend pursuant to § 80.1129(b)(4), then all PTDs which are at any time used to transfer ownership of the renewable fuel or blend shall state, ''This volume of fuel must be used in the designated form, without further blending.''.

(b) Except for transfers to truck carriers, retailers, or wholesale purchaser-consumers, product codes may be used to convey the information required under paragraphs (a)(1) through (a)(4) of this section if such codes are clearly understood by each transferee.

(c) The RIN number required under paragraph (a)(5) of this section must always appear in its entirety.

(d) If a RIN is traded in the EPA–Moderated Trading System (EMTS) as described in § 80.1452(e), the transferor must provide to the transferee documents that include all information as described in paragraphs (a) and (b) of this section and the number of RINs transferred identified by all the following:

(1) Assignment (Assigned or Separated).

(2) Type and/or D code (cellulosic biofuel D=1, biomass-based diesel D=2, advanced biofuel D=3, renewable fuel D=4).

(3) RIN generation year.

§ 80.1454 What are the provisions for renewable fuel production facilities and importers who produce or import less than 10,000 gallons of renewable fuel per year?

(a) Renewable fuel production facilities located within the United States that produce less than 10,000 gallons of renewable fuel each year, and importers who import less than 10,000 gallons of renewable fuel each year, are not required to generate RINs or to assign RINs to batches of renewable fuel. Except as stated in paragraph (b) of this section, such production facilities and importers that do not generate and/or assign RINs to batches of renewable fuel are also exempt from all the following requirements of this subpart:

(1) The recordkeeping requirements of § 80.1451.

(2) The reporting requirements of § 80.1452.

(3) The attest engagement requirements of § 80.1464.

(4) The production outlook report requirements of § 80.1449.

(b)(1) Renewable fuel production facilities and importers who produce or import less than 10,000 gallons of renewable fuel each year and that generate and/or assign RINs to batches of renewable fuel are subject to the provisions of §§ 80.1449 through 80.1452, and 80.1464.

(2) Renewable fuel production facilities and importers who produce or import less than 10,000 gallons of renewable fuel each year but wish to own RINs will be subject to all requirements stated in paragraphs (a)(1) through (a)(4) of this section, and all other applicable requirements of this subpart M.

§ 80.1455 What are the provisions for cellulosic biofuel allowances?

(a) If EPA reduces the applicable volume of cellulosic biofuel pursuant to section 211(o)(7)(D)(i) of the Clean Air Act (42 U.S.C. 7545(o)(7)(D)(i)) for any given compliance year, then EPA will provide cellulosic biofuel allowances for purchase for that compliance year.

(1) The price of these allowances will be set by EPA on an annual basis in accordance with paragraph (d) of this section.

(2) The total allowances available will be equal to the reduced cellulosic biofuel volume established by EPA for the compliance year.

(b) *Use of allowances*. (1) Allowances are only valid for use in the compliance year that they are made available.

(2) Allowances are nonrefundable.

(3) Allowances are nontransferable except if forfeiting the allowances to EPA.

(c) *Purchase of allowances*. (1) Only parties with an RVO for cellulosic biofuel may purchase cellulosic biofuel allowances.

(2) Allowances shall be purchased from EPA at the time that a party submits its annual compliance report to EPA pursuant to § 80.1452(a)(1).

(3) Parties may not purchase more allowances than their cellulosic biofuel RVO minus cellulosic biofuel RINs with a D code of 1 that they own.

(4) Allowances may be used to meet an obligated party's RVOs for the advanced biofuel and total renewable fuel standards.

(d) *Setting the price of allowances*. (1) The price for allowances shall be set equal to the greater of:

(i) $0.25 per allowance, adjusted for inflation in comparison to calendar year 2008; or

(ii) $3.00 less the wholesale price of gasoline per allowance, adjusted for inflation in comparison to calendar year 2008.

(2) The wholesale price of gasoline will be calculated by averaging the most recent twelve monthly values for U.S. Total Gasoline Bulk Sales (Price) by All Sellers as provided by the Energy Information Administration that are available as of September 30 of the year preceding the compliance period.

(3) The inflation adjustment will be calculated by comparing the most recent Consumer Price Index for All Urban Consumers (CPI–U) for All Items expenditure category as provided by the Bureau of Labor Statistics that is available as of September 30 of the year preceding the compliance period to the most recent comparable value reported prior to December 31, 2008. When EPA must set the price of allowances for a compliance year, EPA will calculate the new amounts for paragraphs (d)(1)(i) and (ii) of this section for each year after 2008 and every month where data is available for the year preceding the compliance period.

(e) Cellulosic biofuel allowances under this section will only be able to be purchased on forms and following procedures prescribed by EPA.

§§ 80.1456–80.1459 [Reserved]

§ 80.1460 What acts are prohibited under the RFS program?

(a) *Renewable fuels producer or importer violation.* Except as provided in § 80.1454, no party shall produce or import a renewable fuel without assigning the proper number of gallon-RINs or identifying it by a batch-RIN as required under § 80.1426.

(b) *RIN generation and transfer violations.* No party shall do any of the following:

(1) Generate a RIN for a fuel that is not a renewable fuel, or for which the applicable renewable fuel volume was not produced.

(2) Create or transfer to any party a RIN that is invalid under § 80.1431.

(3) Transfer to any party a RIN that is not properly identified as required under § 80.1425.

(4) Transfer to any party a RIN with a K code of 1 without transferring an appropriate volume of renewable fuel to the same party on the same day.

(5) Introduce into commerce any renewable fuel produced from a feedstock or through a process that is not described in the party's registration information.

(c) *RIN use violations.* No party shall do any of the following:

(1) Fail to acquire sufficient RINs, or use invalid RINs, to meet the party's RVOs under § 80.1427.

(2) Fail to acquire sufficient RINs to meet the party's RVOs under § 80.1430.

(3) Use a validly generated RIN to meet the party's RVOs under § 80.1427, or separate and transfer a validly generated RIN, where the party ultimately uses the renewable fuel volume associated with the RIN in an application other than for use as transportation fuel (as defined in § 80.1401).

(d) *RIN retention violation.* No party shall retain RINs in violation of the requirements in § 80.1428(a)(5).

(e) *Causing a violation.* No party shall cause another party to commit an act in violation of any prohibited act under this section.

(f) *Failure to meet a requirement.* No party shall fail to meet any requirement that applies to that party under this subpart.

§ 80.1461 Who is liable for violations under the RFS program?

(a) *Parties liable for violations of prohibited acts.* (1) Any party who violates a prohibition under § 80.1460(a) through (d) is liable for the violation of that prohibition.

(2) Any party who causes another person to violate a prohibition under § 80.1460(a) through (d) is liable for a violation of § 80.1460(e).

(b) *Parties liable for failure to meet other provisions of this subpart.* (1) Any party who fails to meet a requirement of any provision of this subpart is liable for a violation of that provision.

(2) Any party who causes another party to fail to meet a requirement of any provision of this subpart is liable for causing a violation of that provision.

(c) *Parent corporation liability.* Any parent corporation is liable for any violation of this subpart that is committed by any of its subsidiaries.

(d) *Joint venture liability.* Each partner to a joint venture is jointly and severally liable for any violation of this subpart that is committed by the joint venture operation.

§ 80.1462 [Reserved]

§ 80.1463 What penalties apply under the RFS program?

(a) Any party who is liable for a violation under § 80.1461 is subject a to civil penalty of up to $32,500, as specified in sections 205 and 211(d) of the Clean Air Act, for every day of each such violation and the amount of economic benefit or savings resulting from each violation.

(b) Any party liable under § 80.1461(a) for a violation of § 80.1460(c) for failure to meet its RVOs, or § 80.1460(e) for causing another party to fail to meet their RVOs, during any averaging period, is subject to a separate day of violation for each day in the averaging period.

(c) Any party liable under § 80.1461(b) for failure to meet, or causing a failure to meet, a requirement of any provision of this subpart is liable for a separate day of violation for each day such a requirement remains unfulfilled.

§ 80.1464 What are the attest engagement requirements under the RFS program?

The requirements regarding annual attest engagements in §§ 80.125 through 80.127, and 80.130, also apply to any attest engagement procedures required under this subpart M. In addition to any other applicable attest engagement procedures, such as the requirements in § 80.1465, the following annual attest engagement procedures are required under this subpart.

(a) *Obligated parties and exporters.* The following attest procedures shall be completed for any obligated party as stated in § 80.1406(a) or exporter of renewable fuel that is subject to the renewable fuel standard under § 80.1405:

(1) *Annual compliance demonstration report.* (i) Obtain and read a copy of the annual compliance demonstration report required under § 80.1452(a)(1) which contains information regarding all the following:

(A) The obligated party's volume of finished gasoline, reformulated gasoline blendstock for oxygenate blending (RBOB), and conventional gasoline blendstock that becomes finished conventional gasoline upon the addition of oxygenate (CBOB) produced or imported during the reporting year.

(B) RVOs.

(C) RINs used for compliance.

(ii) Obtain documentation of any volumes of renewable fuel used in gasoline at the refinery or import facility or exported during the reporting year; compute and report as a finding the total volumes of renewable fuel represented in these documents.

(iii) Compare the volumes of gasoline reported to EPA in the report required under § 80.1452(a)(1) with the volumes, excluding any renewable fuel volumes, contained in the inventory reconciliation analysis under § 80.133, and verify that the volumes reported to EPA agree with the volumes in the inventory reconciliation analysis.

(iv) Compute and report as a finding the obligated party's or exporter's RVOs, and any deficit RVOs carried over from the previous year or carried into the subsequent year, and verify that the values agree with the values reported to EPA.

(v) Obtain the database, spreadsheet, or other documentation for all RINs used for compliance during the year being reviewed; calculate the total number of RINs used for compliance by year of generation represented in these documents; state whether this information agrees with the report to EPA and report as a finding any exceptions.

(2) *RIN transaction reports.* (i) Obtain and read copies of a representative sample, selected in accordance with the guidelines in § 80.127, of each RIN transaction type (RINs purchased, RINs sold, RINs retired, RINs reinstated) included in the RIN transaction reports required under § 80.1452(a)(2) for the compliance year.

(ii) Obtain contracts, invoices, or other documentation for the representative samples of RIN transactions; compute the transaction types, transaction dates, and RINs traded; state whether the information agrees with the party's reports to EPA and report as a finding any exceptions.

(3) *RIN activity reports.* (i) Obtain and read copies of all quarterly RIN activity reports required under § 80.1452(a)(3) for the compliance year.

(ii) Obtain the database, spreadsheet, or other documentation used to generate the information in the RIN activity reports; compare the RIN transaction samples reviewed under paragraph (a)(2) of this section with the corresponding entries in the database or spreadsheet and report as a finding any discrepancies; compute the total number of current-year and prior-year RINs owned at the start and end of the quarter, purchased, sold, retired, and reinstated, and for parties that reported RIN activity for RINs assigned to a volume of renewable fuel, the volume of renewable fuel owned at the end of the quarter; as represented in these documents; and state whether this information agrees with the party's reports to EPA.

(b) *Renewable fuel producers and RIN-generating importers.* The following attest procedures shall be completed for any renewable fuel producer or RIN-generating importer:

(1) *Renewable fuel production reports.* (i) Obtain and read copies of the renewable fuel production reports required under §§ 80.1452(b)(1) and (e)(2) for the compliance year.

(ii) Obtain production data for each renewable fuel batch produced or imported during the year being reviewed; compute the RIN numbers, production dates, types, volumes of denaturant and applicable equivalence values, and production volumes for each batch; state whether this information agrees with the party's reports to EPA and report as a finding any exceptions.

(iii) Verify that the proper number of RINs were generated and assigned for each batch of renewable fuel produced or imported, as required under § 80.1426.

(iv) Obtain product transfer documents for a representative sample, selected in accordance with the guidelines in § 80.127, of renewable fuel batches produced or imported during the year being reviewed; verify that the product transfer documents contain the applicable information required under § 80.1453; verify the accuracy of the information contained in the product transfer documents; report as a finding any product transfer document that does not contain the applicable information required under § 80.1453.

(v) Obtain documentation, as required under § 80.1451(b)(6), associated with feedstock purchases and transfers for a representative sample, selected in accordance with the guidelines in § 80.127, of renewable fuel batches produced or imported during the year being reviewed.

(A) If RINs were generated for a given batch of renewable fuel, verify that feedstocks used meet the definition of renewable biomass in § 80.1401.

(B) If no RINs were generated for a given batch of renewable fuel, verify that feedstocks used do not meet the definition of renewable biomass in § 80.1401 or that there was another reason that the fuel produced without RINs was not renewable fuel.

(2) *RIN transaction reports.* (i) Obtain and read copies of a representative sample, selected in accordance with the guidelines in § 80.127, of each transaction type (RINs purchased, RINs sold, RINs retired, RINs reinstated) included in the RIN transaction reports required under § 80.1452(b)(2) for the compliance year.

(ii) Obtain contracts, invoices, or other documentation for the representative samples of RIN transactions; compute the transaction types, transaction dates, and the RINs traded; state whether this information agrees with the party's reports to EPA and report as a finding any exceptions.

(3) *RIN activity reports.* (i) Obtain and read copies of the quarterly RIN activity reports required under § 80.1452(b)(3) for the compliance year.

(ii) Obtain the database, spreadsheet, or other documentation used to generate the information in the RIN activity reports; compare the RIN transaction samples reviewed under paragraph (b)(2) of this section with the corresponding entries in the database or spreadsheet and report as a finding any discrepancies; compute the total number of current-year and prior-year RINs owned at the start and end of the quarter, purchased, sold, retired, and reinstated, and for parties that reported RIN activity for RINs assigned to a volume of renewable fuel, the volume of renewable fuel owned at the end of the quarter, as represented in these documents; and state whether this information agrees with the party's reports to EPA.

(4) *Independent Third Party Engineering Review.* (i) Obtain documentation of independent third party engineering review required under § 80.1450(b)(2).

(ii) Review and verify the written verification and records generated as part of the independent third party engineering review.

(c) *Other parties owning RINs.* The following attest procedures shall be completed for any party other than an obligated party or renewable fuel producer or importer that owns any RINs during a calendar year:

(1) *RIN transaction reports.* (i) Obtain and read copies of a representative sample, selected in accordance with the guidelines in § 80.127, of each RIN transaction type (RINs purchased, RINs sold, RINs retired, RINs reinstated) included in the RIN transaction reports required under § 80.1452(c)(1) for the compliance year.

(ii) Obtain contracts, invoices, or other documentation for the representative samples of RIN transactions; compute the transaction types, transaction dates, and the RINs traded; state whether this information agrees with the party's reports to EPA and report as a finding any exceptions.

(2) *RIN activity reports.* (i) Obtain and read copies of the quarterly RIN activity reports required under § 80.1452(c)(2) for the compliance year.

(ii) Obtain the database, spreadsheet, or other documentation used to generate the information in the RIN activity reports; compare the RIN transaction samples reviewed under paragraph (c)(1) of this section with the corresponding entries in the database or spreadsheet and report as a finding any discrepancies; compute the total number of current-year and prior-year RINs owned at the start and end of the quarter, purchased, sold, retired, and reinstated, and for parties that reported RIN activity for RINs assigned to a volume of renewable fuel, the volume of renewable fuel owned at the end of the quarter, as represented in these documents; and state whether this information agrees with the party's reports to EPA.

(d) The following submission dates apply to the attest engagements required under this section:

(1) For each compliance year, each party subject to the attest engagement requirements under this section shall cause the reports required under this section to be submitted to EPA by May 31 of the year following the compliance year.

(2) [Reserved]

(e) The party conducting the procedures under this section shall obtain a written representation from a company representative that the copies of the reports required under this section are complete and accurate copies of the reports filed with EPA.

(f) The party conducting the procedures under this section shall identify and report as a finding the commercial computer program used by the party to track the data required by the regulations in this subpart, if any.

§ 80.1465 What are the additional requirements under this subpart for foreign small refiners, foreign small refineries, and importers of RFS–FRFUEL?

(a) *Definitions.* The following additional definitions apply for this subpart:

(1) *Foreign refinery* is a refinery that is located outside the United States, the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands (collectively referred to in this section as ''the United States'').

(2) *Foreign refiner* is a party that meets the definition of refiner under § 80.2(i) for a foreign refinery.

(3) *Foreign small refiner* is a foreign refiner that has received a small refinery exemption under § 80.1441 for one or more of its refineries or a foreign refiner that has received a small refiner exemption under § 80.1442.

(4) *RFS–FRFUEL* is transportation fuel produced at a foreign refinery that has received a small refinery exemption under § 80.1441 or by a foreign refiner with a small refiner exemption under § 80.1442.

(5) *Non-RFS–FRFUEL* is one of the following:

(i) Transportation fuel produced at a foreign refinery that has received a small refinery exemption under § 80.1441 or by a foreign refiner with a small refiner exemption under § 80.1442.

(ii) Transportation fuel produced at a foreign refinery that has not received a small refinery exemption under § 80.1441 or by a foreign refiner that has not received a small refiner exemption under § 80.1442.

(b) *General requirements for RFS–FRFUEL for foreign small refineries and small refiners.* A foreign refiner must do all the following:

(1) Designate, at the time of production, each batch of transportation fuel produced at the foreign refinery that is exported for use in the United States as RFS–FRFUEL.

(2) Meet all requirements that apply to refiners who have received a small refinery or small refiner exemption under this subpart.

(c) *Designation, foreign small refiner certification, and product transfer documents.*

(1) Any foreign small refiner must designate each batch of RFS–FRFUEL as such at the time the transportation fuel is produced.

(2) On each occasion when RFS–FRFUEL is loaded onto a vessel or other transportation mode for transport to the United States, the foreign small refiner shall prepare a certification for each batch of RFS–FRFUEL that meets all the following requirements:

(i) The certification shall include the report of the independent third party under paragraph (d) of this section, and all the following additional information:

(A) The name and EPA registration number of the refinery that produced the RFS–FRFUEL.

(B) [Reserved]

(ii) The identification of the transportation fuel as RFS–FRFUEL.

(iii) The volume of RFS–FRFUEL being transported, in gallons.

(3) On each occasion when any party transfers custody or title to any RFS–FRFUEL prior to its being imported into the United States, it must include all the following information as part of the product transfer document information:

(i) Designation of the transportation fuel as RFS–FRFUEL.

(ii) The certification required under paragraph (c)(2) of this section.

(d) *Load port independent testing and refinery identification.* (1) On each occasion that RFS–FRFUEL is loaded onto a vessel for transport to the United States the foreign small refiner shall have an independent third party do all the following:

(i) Inspect the vessel prior to loading and determine the volume of any tank bottoms.

(ii) Determine the volume of RFS–FRFUEL loaded onto the vessel (exclusive of any tank bottoms before loading).

(iii) Obtain the EPA-assigned registration number of the foreign refinery.

(iv) Determine the name and country of registration of the vessel used to transport the RFS–FRFUEL to the United States.

(v) Determine the date and time the vessel departs the port serving the foreign refinery.

(vi) Review original documents that reflect movement and storage of the RFS–FRFUEL from the foreign refinery to the load port, and from this review determine:

(A) The refinery at which the RFS–FRFUEL was produced; and

(B) That the RFS–FRFUEL remained segregated from Non-RFS–FRFUEL and other RFS–FRFUEL produced at a different refinery.

(2) The independent third party shall submit a report to all the following:

(i) The foreign small refiner, containing the information required under paragraph (d)(1) of this section, to accompany the product transfer documents for the vessel.

(ii) The Administrator, containing the information required under paragraph (d)(1) of this section, within thirty days following the date of the independent third party's inspection. This report shall include a description of the method used to determine the identity of the refinery at which the transportation fuel was produced, assurance that the transportation fuel remained segregated as specified in paragraph (j)(1) of this section, and a description of the transportation fuel's movement and storage between production at the source refinery and vessel loading.

(3) The independent third party must do all the following:

(i) Be approved in advance by EPA, based on a demonstration of ability to perform the procedures required in this paragraph (d).

(ii) Be independent under the criteria specified in § 80.65(f)(2)(iii).

(iii) Sign a commitment that contains the provisions specified in paragraph (f) of this section with regard to activities, facilities, and documents relevant to compliance with the requirements of this paragraph (d).

(e) *Comparison of load port and port of entry testing.* (1)(i) Any foreign small refiner or foreign small refinery and any United States importer of RFS–FRFUEL shall compare the results from the load port testing under paragraph (d) of this section, with the port of entry testing as reported under paragraph (k) of this section, for the volume of transportation fuel, except as specified in paragraph (e)(1)(ii) of this section.

(ii) Where a vessel transporting RFS–FRFUEL off loads this transportation fuel at more than one United States port of entry, the requirements of paragraph (e)(1)(i) of this section do not apply at subsequent ports of entry if the United States importer obtains a certification from the vessel owner that the requirements of paragraph (e)(1)(i) of this section were met and that the vessel has not loaded any transportation fuel or blendstock between the first United States port of entry and the subsequent port of entry.

(2) If the temperature-corrected volumes determined at the port of entry and at the load port differ by more than one percent, the United States importer and the foreign small refiner or foreign small refinery shall not treat the transportation fuel as RFS–FRFUEL and the importer shall include the volume of transportation fuel in the importer's RFS compliance calculations.

(f) *Foreign refiner commitments.* Any small foreign refiner shall commit to and comply with the provisions contained in this paragraph (f) as a condition to being approved for a small refinery or small refiner exemption under this subpart.

(1) Any United States Environmental Protection Agency inspector or auditor

must be given full, complete, and immediate access to conduct inspections and audits of the foreign refinery.

(i) Inspections and audits may be either announced in advance by EPA, or unannounced.

(ii) Access will be provided to any location where:

(A) Transportation fuel is produced;

(B) Documents related to refinery operations are kept; and

(C) RFS–FRFUEL is stored or transported between the foreign refinery and the United States, including storage tanks, vessels and pipelines.

(iii) Inspections and audits may be by EPA employees or contractors to EPA.

(iv) Any documents requested that are related to matters covered by inspections and audits must be provided to an EPA inspector or auditor on request.

(v) Inspections and audits by EPA may include review and copying of any documents related to all the following:

(A) The volume of RFS–FRFUEL.

(B) The proper classification of transportation fuel as being RFS–FRFUEL or as not being RFS–FRFUEL.

(C) Transfers of title or custody to RFS–FRFUEL.

(D) Testing of RFS–FRFUEL.

(E) Work performed and reports prepared by independent third parties and by independent auditors under the requirements of this section, including work papers.

(vi) Inspections and audits by EPA may include interviewing employees.

(vii) Any employee of the foreign refiner must be made available for interview by the EPA inspector or auditor, on request, within a reasonable time period.

(viii) English language translations of any documents must be provided to an EPA inspector or auditor, on request, within 10 working days.

(ix) English language interpreters must be provided to accompany EPA inspectors and auditors, on request.

(2) An agent for service of process located in the District of Columbia shall be named, and service on this agent constitutes service on the foreign refiner or any employee of the foreign refiner for any action by EPA or otherwise by the United States related to the requirements of this subpart.

(3) The forum for any civil or criminal enforcement action related to the provisions of this section for violations of the Clean Air Act or regulations promulgated thereunder shall be governed by the Clean Air Act, including the EPA administrative forum where allowed under the Clean Air Act.

(4) United States substantive and procedural laws shall apply to any civil or criminal enforcement action against the foreign refiner or any employee of the foreign refiner related to the provisions of this section.

(5) Submitting an application for a small refinery or small refiner exemption, or producing and exporting transportation fuel under such exemption, and all other actions to comply with the requirements of this subpart relating to such exemption constitute actions or activities covered by and within the meaning of the provisions of 28 U.S.C. 1605(a)(2), but solely with respect to actions instituted against the foreign refiner, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign refiner under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(6) The foreign refiner, or its agents or employees, will not seek to detain or to impose civil or criminal remedies against EPA inspectors or auditors, whether EPA employees or EPA contractors, for actions performed within the scope of EPA employment related to the provisions of this section.

(7) The commitment required by this paragraph (f) shall be signed by the owner or president of the foreign refiner business.

(8) In any case where RFS–FRFUEL produced at a foreign refinery is stored or transported by another company between the refinery and the vessel that transports the RFS–FRFUEL to the United States, the foreign refiner shall obtain from each such other company a commitment that meets the requirements specified in paragraphs (f)(1) through (f)(7) of this section, and these commitments shall be included in the foreign refiner's application for a small refinery or small refiner exemption under this subpart.

(g) *Sovereign immunity.* By submitting an application for a small refinery or small refiner exemption under this subpart, or by producing and exporting transportation fuel to the United States under such exemption, the foreign refiner, and its agents and employees, without exception, become subject to the full operation of the administrative and judicial enforcement powers and provisions of the United States without limitation based on sovereign immunity, with respect to actions instituted against the foreign refiner, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign refiner under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(h) *Bond posting.* Any foreign refiner shall meet the requirements of this paragraph (h) as a condition to approval of a small foreign refinery or small foreign refiner exemption under this subpart.

(1) The foreign refiner shall post a bond of the amount calculated using the following equation:

$$\text{Bond} = G * \$\,0.01$$

Where:

Bond = amount of the bond in United States dollars.

G = the largest volume of transportation fuel produced at the foreign refinery and exported to the United States, in gallons, during a single calendar year among the most recent of the following calendar years, up to a maximum of five calendar years: the calendar year immediately preceding the date the refinery's or refiner's application is submitted, the calendar year the application is submitted, and each succeeding calendar year.

(2) Bonds shall be posted by:

(i) Paying the amount of the bond to the Treasurer of the United States;

(ii) Obtaining a bond in the proper amount from a third party surety agent that is payable to satisfy United States administrative or judicial judgments against the foreign refiner, provided EPA agrees in advance as to the third party and the nature of the surety agreement; or

(iii) An alternative commitment that results in assets of an appropriate liquidity and value being readily available to the United States, provided EPA agrees in advance as to the alternative commitment.

(3) Bonds posted under this paragraph (h) shall:

(i) Be used to satisfy any judicial judgment that results from an administrative or judicial enforcement action for conduct in violation of this subpart, including where such conduct violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413);

(ii) Be provided by a corporate surety that is listed in the United States Department of Treasury Circular 570 ''Companies Holding Certificates of Authority as Acceptable Sureties on Federal Bonds''; and

(iii) Include a commitment that the bond will remain in effect for at least five years following the end of latest annual reporting period that the foreign refiner produces transportation fuel pursuant to the requirements of this subpart.

(4) On any occasion a foreign refiner bond is used to satisfy any judgment, the foreign refiner shall increase the bond to cover the amount used within 90 days of the date the bond is used.

(5) If the bond amount for a foreign refiner increases, the foreign refiner shall increase the bond to cover the shortfall within 90 days of the date the bond amount changes. If the bond amount decreases, the foreign refiner may reduce the amount of the bond beginning 90 days after the date the bond amount changes.

(i) *English language reports.* Any document submitted to EPA by a foreign refiner shall be in English, or shall include an English language translation.

(j) *Prohibitions.* (1) No party may combine RFS–FRFUEL with any Non-RFS–FRFUEL, and no party may combine RFS–FRFUEL with any RFS–FRFUEL produced at a different refinery, until the importer has met all the requirements of paragraph (k) of this section.

(2) No foreign refiner or other party may cause another party to commit an action prohibited in paragraph (j)(1) of this section, or that otherwise violates the requirements of this section.

(k) *United States importer requirements.* Any United States importer of RFS–FRFUEL shall meet the following requirements:

(1) Each batch of imported RFS–FRFUEL shall be classified by the importer as being RFS–FRFUEL.

(2) Transportation fuel shall be classified as RFS–FRFUEL according to the designation by the foreign refiner if this designation is supported by product transfer documents prepared by the foreign refiner as required in paragraph (c) of this section. Additionally, the importer shall comply with all requirements of this subpart applicable to importers.

(3) For each transportation fuel batch classified as RFS–FRFUEL, any United States importer shall have an independent third party do all the following:

(i) Determine the volume of transportation fuel in the vessel.

(ii) Use the foreign refiner's RFS–FRFUEL certification to determine the name and EPA-assigned registration number of the foreign refinery that produced the RFS–FRFUEL.

(iii) Determine the name and country of registration of the vessel used to transport the RFS–FRFUEL to the United States.

(iv) Determine the date and time the vessel arrives at the United States port of entry.

(4) Any importer shall submit reports within 30 days following the date any vessel transporting RFS–FRFUEL arrives at the United States port of entry to:

(i) The Administrator, containing the information determined under paragraph (k)(3) of this section; and

(ii) The foreign refiner, containing the information determined under paragraph (k)(3)(i) of this section, and including identification of the port at which the product was off loaded.

(5) Any United States importer shall meet all other requirements of this subpart for any imported transportation fuel that is not classified as RFS–FRFUEL under paragraph (k)(2) of this section.

(l) *Truck imports of RFS–FRFUEL produced at a foreign refinery.* (1) Any refiner whose RFS–FRFUEL is transported into the United States by truck may petition EPA to use alternative procedures to meet all the following requirements:

(i) Certification under paragraph (c)(2) of this section.

(ii) Load port and port of entry testing requirements under paragraphs (d) and (e) of this section.

(iii) Importer testing requirements under paragraph (k)(3) of this section.

(2) These alternative procedures must ensure RFS–FRFUEL remains segregated from Non-RFS–FRFUEL until it is imported into the United States. The petition will be evaluated based on whether it adequately addresses all the following:

(i) Provisions for monitoring pipeline shipments, if applicable, from the refinery, that ensure segregation of RFS–FRFUEL from that refinery from all other transportation fuel.

(ii) Contracts with any terminals and/or pipelines that receive and/or transport RFS–FRFUEL that prohibit the commingling of RFS–FRFUEL with Non-RFS–FRFUEL or RFS–FRFUEL from other foreign refineries.

(iii) Attest procedures to be conducted annually by an independent third party that review loading records and import documents based on volume reconciliation, or other criteria, to confirm that all RFS–FRFUEL remains segregated throughout the distribution system.

(3) The petition described in this section must be submitted to EPA along with the application for a small refinery or small refiner exemption under this subpart.

(m) *Additional attest requirements for importers of RFS–FRFUEL.* The following additional procedures shall be carried out by any importer of RFS–FRFUEL as part of the attest engagement required for importers under this subpart M.

(1) Obtain listings of all tenders of RFS–FRFUEL. Agree the total volume of tenders from the listings to the transportation fuel inventory reconciliation analysis required in § 80.133(b), and to the volumes determined by the third party under paragraph (d) of this section.

(2) For each tender under paragraph (m)(1) of this section, where the transportation fuel is loaded onto a marine vessel, report as a finding the name and country of registration of each vessel, and the volumes of RFS–FRFUEL loaded onto each vessel.

(3) Select a sample from the list of vessels identified per paragraph (m)(2) of this section used to transport RFS–FRFUEL, in accordance with the guidelines in § 80.127, and for each vessel selected perform all the following:

(i) Obtain the report of the independent third party, under paragraph (d) of this section.

(A) Agree the information in these reports with regard to vessel identification and transportation fuel volume.

(B) Identify, and report as a finding, each occasion the load port and port of entry volume results differ by more than the amount allowed in paragraph (e)(2) of this section, and determine whether all of the requirements of paragraph (e)(2) of this section have been met.

(ii) Obtain the documents used by the independent third party to determine transportation and storage of the RFS–FRFUEL from the refinery to the load port, under paragraph (d) of this section. Obtain tank activity records for any storage tank where the RFS–FRFUEL is stored, and pipeline activity records for any pipeline used to transport the RFS–FRFUEL prior to being loaded onto the vessel. Use these records to determine whether the RFS–FRFUEL was produced at the refinery that is the subject of the attest engagement, and whether the RFS–FRFUEL was mixed with any Non-RFS–FRFUEL or any RFS–FRFUEL produced at a different refinery.

(4) Select a sample from the list of vessels identified per paragraph (m)(2) of this section used to transport RFS–FRFUEL, in accordance with the guidelines in § 80.127, and for each vessel selected perform all the following:

(i) Obtain a commercial document of general circulation that lists vessel arrivals and departures, and that includes the port and date of departure of the vessel, and the port of entry and date of arrival of the vessel.

(ii) Agree the vessel's departure and arrival locations and dates from the independent third party and United States importer reports to the information contained in the commercial document.

(5) Obtain separate listings of all tenders of RFS–FRFUEL, and perform all the following:

(i) Agree the volume of tenders from the listings to the transportation fuel inventory reconciliation analysis in § 80.133(b).

(ii) Obtain a separate listing of the tenders under this paragraph (m)(5) where the transportation fuel is loaded onto a marine vessel. Select a sample from this listing in accordance with the guidelines in § 80.127, and obtain a commercial document of general circulation that lists vessel arrivals and departures, and that includes the port and date of departure and the ports and dates where the transportation fuel was off loaded for the selected vessels. Determine and report as a finding the country where the transportation fuel was off loaded for each vessel selected.

(6) In order to complete the requirements of this paragraph (m), an auditor shall do all the following:

(i) Be independent of the foreign refiner or importer.

(ii) Be licensed as a Certified Public Accountant in the United States and a citizen of the United States, or be approved in advance by EPA based on a demonstration of ability to perform the procedures required in §§ 80.125 through 80.127, 80.130, 80.1464, and this paragraph (m).

(iii) Sign a commitment that contains the provisions specified in paragraph (f) of this section with regard to activities and documents relevant to compliance with the requirements of §§ 80.125 through 80.127, 80.130, 80.1464, and this paragraph (m).

(n) *Withdrawal or suspension of foreign small refiner or foreign small refinery status.* EPA may withdraw or suspend a foreign refiner's small refinery or small refiner exemption where:

(1) A foreign refiner fails to meet any requirement of this section;

(2) A foreign government fails to allow EPA inspections as provided in paragraph (f)(1) of this section;

(3) A foreign refiner asserts a claim of, or a right to claim, sovereign immunity in an action to enforce the requirements in this subpart; or

(4) A foreign refiner fails to pay a civil or criminal penalty that is not satisfied using the foreign refiner bond specified in paragraph (h) of this section.

(o) *Additional requirements for applications, reports and certificates.* Any application for a small refinery or small refiner exemption, alternative procedures under paragraph (l) of this section, any report, certification, or other submission required under this section shall be:

(1) Submitted in accordance with procedures specified by the Administrator, including use of any forms that may be specified by the Administrator.

(2) Signed by the president or owner of the foreign refiner company, or by that party's immediate designee, and shall contain the following declaration:

''I hereby certify: (1) That I have actual authority to sign on behalf of and to bind [insert name of foreign refiner] with regard to all statements contained herein; (2) that I am aware that the information contained herein is being Certified, or submitted to the United States Environmental Protection Agency, under the requirements of 40 CFR part 80, subpart M, and that the information is material for determining compliance under these regulations; and (3) that I have read and understand the information being Certified or submitted, and this information is true, complete and correct to the best of my knowledge and belief after I have taken reasonable and appropriate steps to verify the accuracy thereof. I affirm that I have read and understand the provisions of 40 CFR part 80, subpart M, including 40 CFR 80.1465 apply to [INSERT NAME OF FOREIGN REFINER]. Pursuant to Clean Air Act section 113(c) and 18 U.S.C. 1001, the penalty for furnishing false, incomplete or misleading information in this certification or submission is a fine of up to $10,000 U.S., and/or imprisonment for up to five years.''.

§ 80.1466 What are the additional requirements under this subpart for foreign producers and importers of renewable fuels?

(a) *Foreign producer of renewable fuel.* For purposes of this subpart, a foreign producer of renewable fuel is a party located outside the United States, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands (collectively referred to in this section as ''the United States'') that has been approved by EPA to assign RINs to renewable fuel that the foreign producer produces and exports to the United States, hereinafter referred to as a ''foreign producer'' under this section.

(b) *General requirements.* An approved foreign producer under this section must meet all requirements that apply to renewable fuel producers under this subpart.

(c) *Designation, foreign producer certification, and product transfer documents.* (1) Any approved foreign producer under this section must designate each batch of renewable fuel as ''RFS–FRRF'' at the time the renewable fuel is produced.

(2) On each occasion when RFS–FRRF is loaded onto a vessel or other transportation mode for transport to the United States, the foreign producer shall prepare a certification for each batch of RFS–FRRF; the certification shall include the report of the independent third party under paragraph (d) of this section, and all the following additional information:

(i) The name and EPA registration number of the company that produced the RFS–FRRF.

(ii) The identification of the renewable fuel as RFS–FRRF.

(iii) The volume of RFS–FRRF being transported, in gallons.

(3) On each occasion when any party transfers custody or title to any RFS–FRRF prior to its being imported into the United States, it must include all the following information as part of the product transfer document information:

(i) Designation of the renewable fuel as RFS–FRRF.

(ii) The certification required under paragraph (c)(2) of this section.

(d) *Load port independent testing and refinery identification.* (1) On each occasion that RFS–FRRF is loaded onto a vessel for transport to the United States the foreign producer shall have an independent third party do all the following:

(i) Inspect the vessel prior to loading and determine the volume of any tank bottoms.

(ii) Determine the volume of RFS–FRRF loaded onto the vessel (exclusive of any tank bottoms before loading).

(iii) Obtain the EPA-assigned registration number of the foreign producer.

(iv) Determine the name and country of registration of the vessel used to transport the RFS–FRRF to the United States.

(v) Determine the date and time the vessel departs the port serving the foreign producer.

(vi) Review original documents that reflect movement and storage of the RFS–FRRF from the foreign producer to the load port, and from this review determine all the following:

(A) The facility at which the RFS–FRRF was produced.

(B) That the RFS–FRRF remained segregated from Non-RFS–FRRF and other RFS–FRRF produced by a different foreign producer.

(2) The independent third party shall submit a report to the following:

(i) The foreign producer, containing the information required under paragraph (d)(1) of this section, to accompany the product transfer documents for the vessel.

(ii) The Administrator, containing the information required under paragraph (d)(1) of this section, within thirty days following the date of the independent third party's inspection. This report shall include a description of the method used to determine the identity of the foreign producer facility at which the renewable fuel was produced, assurance that the renewable fuel remained segregated as specified in paragraph (j)(1) of this section, and a description of the renewable fuel's movement and storage between production at the source facility and vessel loading.

(3) The independent third party must:

(i) Be approved in advance by EPA, based on a demonstration of ability to perform the procedures required in this paragraph (d);

(ii) Be independent under the criteria specified in § 80.65(e)(2)(iii); and

(iii) Sign a commitment that contains the provisions specified in paragraph (f) of this section with regard to activities, facilities and documents relevant to compliance with the requirements of this paragraph (d).

(e) *Comparison of load port and port of entry testing.* (1)(i) Any foreign producer and any United States importer of RFS–FRRF shall compare the results from the load port testing under paragraph (d) of this section, with the port of entry testing as reported under paragraph (k) of this section, for the volume of renewable fuel, except as specified in paragraph (e)(1)(ii) of this section.

(ii) Where a vessel transporting RFS–FRRF off loads the renewable fuel at more than one United States port of entry, the requirements of paragraph (e)(1)(i) of this section do not apply at subsequent ports of entry if the United States importer obtains a certification from the vessel owner that the requirements of paragraph (e)(1)(i) of this section were met and that the vessel has not loaded any renewable fuel between the first United States port of entry and the subsequent port of entry.

(2)(i) If the temperature-corrected volumes determined at the port of entry and at the load port differ by more than one percent, the number of RINs associated with the renewable fuel shall be calculated based on the lesser of the two volumes in paragraph (e)(1)(i) of this section.

(ii) Where the port of entry volume is the lesser of the two volumes in paragraph (e)(1)(i) of this section, the importer shall calculate the difference between the number of RINs originally assigned by the foreign producer and the number of RINs calculated under § 80.1426 for the volume of renewable fuel as measured at the port of entry, and retire that amount of RINs in accordance with paragraph (k)(4) of this section.

(f) *Foreign producer commitments.* Any foreign producer shall commit to and comply with the provisions contained in this paragraph (f) as a condition to being approved as a foreign producer under this subpart.

(1) Any United States Environmental Protection Agency inspector or auditor must be given full, complete, and immediate access to conduct inspections and audits of the foreign producer facility.

(i) Inspections and audits may be either announced in advance by EPA, or unannounced.

(ii) Access will be provided to any location where:

(A) Renewable fuel is produced;

(B) Documents related to renewable fuel producer operations are kept; and

(C) RFS–FRRF is stored or transported between the foreign producer and the United States, including storage tanks, vessels and pipelines.

(iii) Inspections and audits may be by EPA employees or contractors to EPA.

(iv) Any documents requested that are related to matters covered by inspections and audits must be provided to an EPA inspector or auditor on request.

(v) Inspections and audits by EPA may include review and copying of any documents related to the following:

(A) The volume of RFS–FRRF.

(B) The proper classification of gasoline as being RFS–FRRF.

(C) Transfers of title or custody to RFS–FRRF.

(D) Work performed and reports prepared by independent third parties and by independent auditors under the requirements of this section, including work papers.

(vi) Inspections and audits by EPA may include interviewing employees.

(vii) Any employee of the foreign producer must be made available for interview by the EPA inspector or auditor, on request, within a reasonable time period.

(viii) English language translations of any documents must be provided to an EPA inspector or auditor, on request, within 10 working days.

(ix) English language interpreters must be provided to accompany EPA inspectors and auditors, on request.

(2) An agent for service of process located in the District of Columbia shall be named, and service on this agent constitutes service on the foreign producer or any employee of the foreign producer for any action by EPA or otherwise by the United States related to the requirements of this subpart.

(3) The forum for any civil or criminal enforcement action related to the provisions of this section for violations of the Clean Air Act or regulations promulgated thereunder shall be governed by the Clean Air Act, including the EPA administrative forum where allowed under the Clean Air Act.

(4) United States substantive and procedural laws shall apply to any civil or criminal enforcement action against the foreign producer or any employee of the foreign producer related to the provisions of this section.

(5) Applying to be an approved foreign producer under this section, or producing or exporting renewable fuel under such approval, and all other actions to comply with the requirements of this subpart relating to such approval constitute actions or activities covered by and within the meaning of the provisions of 28 U.S.C. 1605(a)(2), but solely with respect to actions instituted against the foreign producer, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign producer under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(6) The foreign producer, or its agents or employees, will not seek to detain or to impose civil or criminal remedies against EPA inspectors or auditors, whether EPA employees or EPA contractors, for actions performed within the scope of EPA employment related to the provisions of this section.

(7) The commitment required by this paragraph (f) shall be signed by the owner or president of the foreign producer company.

(8) In any case where RFS–FRRF produced at a foreign producer facility is stored or transported by another company between the refinery and the vessel that transports the RFS–FRRF to the United States, the foreign producer shall obtain from each such other company a commitment that meets the requirements specified in paragraphs (f)(1) through (7) of this section, and these commitments shall be included in the foreign producer's application to be an approved foreign producer under this subpart.

(g) *Sovereign immunity.* By submitting an application to be an approved foreign producer under this subpart, or by producing and exporting renewable fuel to the United States under such approval, the foreign producer, and its agents and employees, without exception, become subject to the full operation of the administrative and judicial enforcement powers and provisions of the United States without limitation based on sovereign immunity, with respect to actions instituted against the foreign producer, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign producer under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(h) *Bond posting.* Any foreign producer shall meet the requirements of this paragraph (h) as a condition to approval as a foreign producer under this subpart.

(1) The foreign producer shall post a bond of the amount calculated using the following equation:

Bond = G * $ 0.01

Where:

Bond = amount of the bond in U.S. dollars.

G = the largest volume of renewable fuel produced at the foreign producer's facility and exported to the United States, in gallons, during a single calendar year among the most recent of the following calendar years, up to a maximum of five calendar years: the calendar year immediately preceding the date the refinery's application is submitted, the calendar year the application is submitted, and each succeeding calendar year.

(2) Bonds shall be posted by any of the following methods:

(i) Paying the amount of the bond to the Treasurer of the United States.

(ii) Obtaining a bond in the proper amount from a third party surety agent that is payable to satisfy United States administrative or judicial judgments against the foreign producer, provided EPA agrees in advance as to the third party and the nature of the surety agreement.

(iii) An alternative commitment that results in assets of an appropriate liquidity and value being readily available to the United States provided EPA agrees in advance as to the alternative commitment.

(3) Bonds posted under this paragraph (h) shall:

(i) Be used to satisfy any judicial judgment that results from an administrative or judicial enforcement action for conduct in violation of this subpart, including where such conduct violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413);

(ii) Be provided by a corporate surety that is listed in the United States Department of Treasury Circular 570 ''Companies Holding Certificates of Authority as Acceptable Sureties on Federal Bonds''; and

(iii) Include a commitment that the bond will remain in effect for at least five years following the end of latest annual reporting period that the foreign producer produces renewable fuel pursuant to the requirements of this subpart.

(4) On any occasion a foreign producer bond is used to satisfy any judgment, the foreign producer shall increase the bond to cover the amount used within 90 days of the date the bond is used.

(5) If the bond amount for a foreign producer increases, the foreign producer shall increase the bond to cover the shortfall within 90 days of the date the bond amount changes. If the bond amount decreases, the foreign refiner may reduce the amount of the bond beginning 90 days after the date the bond amount changes.

(i) *English language reports.* Any document submitted to EPA by a foreign producer shall be in English, or shall include an English language translation.

(j) *Prohibitions.* (1) No party may combine RFS–FRRF with any Non-RFS–FRRF, and no party may combine RFS–FRRF with any RFS–FRRF produced at a different refinery, until the importer has met all the requirements of paragraph (k) of this section.

(2) No foreign producer or other party may cause another party to commit an action prohibited in paragraph (j)(1) of this section, or that otherwise violates the requirements of this section.

(k) *Requirements for United States importers of RFS–FRRF.* Any United States importer shall meet all the following requirements:

(1) Each batch of imported RFS–FRRF shall be classified by the importer as being RFS–FRRF.

(2) Renewable fuel shall be classified as RFS–FRRF according to the designation by the foreign producer if this designation is supported by product transfer documents prepared by the foreign producer as required in paragraph (c) of this section.

(3) For each renewable fuel batch classified as RFS–FRRF, any United States importer shall have an independent third party do all the following:

(i) Determine the volume of gasoline in the vessel.

(ii) Use the foreign producer's RFS–FRRF certification to determine the name and EPA-assigned registration number of the foreign producer that produced the RFS–FRRF.

(iii) Determine the name and country of registration of the vessel used to transport the RFS–FRRF to the United States.

(iv) Determine the date and time the vessel arrives at the United States port of entry.

(4) Where the importer is required to retire RINs under paragraph (e)(2) of this section, the importer must report the retired RINs in the applicable reports under § 80.1452.

(5) Any importer shall submit reports within 30 days following the date any vessel transporting RFS–FRRF arrives at the United States port of entry to all the following:

(i) The Administrator, containing the information determined under paragraph (k)(3) of this section.

(ii) The foreign producer, containing the information determined under paragraph (k)(3)(i) of this section, and including identification of the port at which the product was off loaded, and any RINs retired under paragraph (e)(2) of this section.

(6) Any United States importer shall meet all other requirements of this subpart for any imported ethanol or other renewable fuel that is not classified as RFS–FRRF under paragraph (k)(2) of this section.

(l) *Truck imports of RFS–FRRF produced by a foreign producer.* (1) Any foreign producer whose RFS–FRRF is transported into the United States by truck may petition EPA to use alternative procedures to meet all the following requirements:

(i) Certification under paragraph (c)(2) of this section.

(ii) Load port and port of entry testing under paragraphs (d) and (e) of this section.

(iii) Importer testing under paragraph (k)(3) of this section.

(2) These alternative procedures must ensure RFS–FRRF remains segregated from Non-RFS–FRRF until it is imported into the United States. The petition will be evaluated based on whether it adequately addresses the following:

(i) Contracts with any facilities that receive and/or transport RFS–FRRF that prohibit the commingling of RFS–FRRF with Non-RFS–FRRF or RFS–FRRF from other foreign producers.

(ii) Attest procedures to be conducted annually by an independent third party that review loading records and import documents based on volume reconciliation to confirm that all RFS–FRRF remains segregated.

(3) The petition described in this section must be submitted to EPA along with the application for approval as a foreign producer under this subpart.

(m) *Additional attest requirements for producers of RFS–FRRF.* The following additional procedures shall be carried out by any producer of RFS–FRRF as part of the attest engagement required for renewable fuel producers under this subpart M.

(1) Obtain listings of all tenders of RFS–FRRF. Agree the total volume of tenders from the listings to the volumes determined by the third party under paragraph (d) of this section.

(2) For each tender under paragraph (m)(1) of this section, where the renewable fuel is loaded onto a marine vessel, report as a finding the name and country of registration of each vessel, and the volumes of RFS–FRRF loaded onto each vessel.

(3) Select a sample from the list of vessels identified in paragraph (m)(2) of this section used to transport RFS–FRRF, in accordance with the guidelines in § 80.127, and for each vessel selected perform all the following:

(i) Obtain the report of the independent third party, under paragraph (d) of this section, and of the United States importer under paragraph (k) of this section.

(A) Agree the information in these reports with regard to vessel identification and renewable fuel volume.

(B) Identify, and report as a finding, each occasion the load port and port of entry volume results differ by more than the amount allowed in paragraph (e) of this section, and determine whether the importer retired the appropriate amount of RINs as required under paragraph (e)(2) of this section, and submitted the applicable reports under § 80.1452 in accordance with paragraph (k)(4) of this section.

(ii) Obtain the documents used by the independent third party to determine transportation and storage of the RFS–FRRF from the foreign producer's facility to the load port, under paragraph (d) of this section. Obtain tank activity records for any storage tank where the RFS–FRRF is stored, and activity records for any mode of transportation used to transport the RFS–FRFUEL prior to being loaded onto the vessel. Use these records to determine whether the RFS–FRRF was produced at the foreign producer's facility that is the subject of the attest engagement, and whether the RFS–FRRF was mixed with any Non-RFS–FRRF or any RFS–FRRF produced at a different facility.

(4) Select a sample from the list of vessels identified in paragraph (m)(2) of this section used to transport RFS–FRRF, in accordance with the guidelines in § 80.127, and for each vessel selected perform the following:

(i) Obtain a commercial document of general circulation that lists vessel arrivals and departures, and that includes the port and date of departure of the vessel, and the port of entry and date of arrival of the vessel.

(ii) Agree the vessel's departure and arrival locations and dates from the independent third party and United States importer reports to the information contained in the commercial document.

(5) Obtain a separate listing of the tenders under this paragraph (m)(5) where the RFS–FRRF is loaded onto a marine vessel. Select a sample from this listing in accordance with the guidelines in § 80.127, and obtain a commercial document of general circulation that lists vessel arrivals and departures, and that includes the port and date of departure and the ports and dates where the renewable fuel was off loaded for the selected vessels. Determine and report as a finding the country where the renewable fuel was off loaded for each vessel selected.

(6) In order to complete the requirements of this paragraph (m) an auditor shall:

(i) Be independent of the foreign producer;

(ii) Be licensed as a Certified Public Accountant in the United States and a citizen of the United States, or be approved in advance by EPA based on a demonstration of ability to perform the procedures required in §§ 80.125 through 80.127, 80.130, 80.1464, and this paragraph (m); and

(iii) Sign a commitment that contains the provisions specified in paragraph (f) of this section with regard to activities and documents relevant to compliance with the requirements of §§ 80.125 through 80.127, 80.130, 80.1464, and this paragraph (m).

(n) *Withdrawal or suspension of foreign producer approval.* EPA may withdraw or suspend a foreign producer's approval where any of the following occur:

(1) A foreign producer fails to meet any requirement of this section.

(2) A foreign government fails to allow EPA inspections as provided in paragraph (f)(1) of this section.

(3) A foreign producer asserts a claim of, or a right to claim, sovereign immunity in an action to enforce the requirements in this subpart.

(4) A foreign producer fails to pay a civil or criminal penalty that is not satisfied using the foreign producer bond specified in paragraph (g) of this section.

(o) *Additional requirements for applications, reports and certificates.* Any application for approval as a foreign producer, alternative procedures under paragraph (l) of this section, any report, certification, or other submission required under this section shall be:

(1) Submitted in accordance with procedures specified by the Administrator, including use of any forms that may be specified by the Administrator.

(2) Signed by the president or owner of the foreign producer company, or by that party's immediate designee, and shall contain the following declaration:

''I hereby certify: 1) That I have actual authority to sign on behalf of and to bind [insert name of foreign producer] with regard to all statements contained herein; 2) that I am aware that the information contained herein is being Certified, or submitted to the United States Environmental Protection Agency, under the requirements of 40 CFR part 80, subpart M, and that the information is material for determining compliance under these regulations; and 3) that I have read and understand the information being Certified or submitted, and this information is true, complete and correct to the best of my knowledge and belief after I have taken reasonable and appropriate steps to verify the accuracy thereof. I affirm that I have read and understand the provisions of 40 CFR part 80, subpart M, including 40 CFR 80.1465 apply to [insert name of foreign producer]. Pursuant to Clean Air Act section 113(c) and 18 U.S.C. 1001, the penalty for furnishing false, incomplete or misleading information in this certification or submission is a fine of up to $10,000 U.S., and/or imprisonment for up to five years.''.

§ 80.1467 What are the additional requirements under this subpart for a foreign RIN owner?

(a) *Foreign RIN owner.* For purposes of this subpart, a foreign RIN owner is a party located outside the United States, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands (collectively referred to in this section as ''the United States'') that has been approved by EPA to own RINs.

(b) *General requirement.* An approved foreign RIN owner must meet all requirements that apply to parties who own RINs under this subpart.

(c) *Foreign RIN owner commitments*. Any party shall commit to and comply with the provisions contained in this paragraph (c) as a condition to being approved as a foreign RIN owner under this subpart.

(1) Any United States Environmental Protection Agency inspector or auditor must be given full, complete, and immediate access to conduct inspections and audits of the foreign RIN owner's place of business.

(i) Inspections and audits may be either announced in advance by EPA, or unannounced.

(ii) Access will be provided to any location where documents related to RINs the foreign RIN owner has obtained, sold, transferred or held are kept.

(iii) Inspections and audits may be by EPA employees or contractors to EPA.

(iv) Any documents requested that are related to matters covered by inspections and audits must be provided to an EPA inspector or auditor on request.

(v) Inspections and audits by EPA may include review and copying of any documents related to the following:

(A) Transfers of title to RINs.

(B) Work performed and reports prepared by independent auditors under the requirements of this section, including work papers.

(vi) Inspections and audits by EPA may include interviewing employees.

(vii) Any employee of the foreign RIN owner must be made available for interview by the EPA inspector or auditor, on request, within a reasonable time period.

(viii) English language translations of any documents must be provided to an EPA inspector or auditor, on request, within 10 working days.

(ix) English language interpreters must be provided to accompany EPA inspectors and auditors, on request.

(2) An agent for service of process located in the District of Columbia shall be named, and service on this agent constitutes service on the foreign RIN owner or any employee of the foreign RIN owner for any action by EPA or otherwise by the United States related to the requirements of this subpart.

(3) The forum for any civil or criminal enforcement action related to the provisions of this section for violations of the Clean Air Act or regulations promulgated thereunder shall be governed by the Clean Air Act, including the EPA administrative forum where allowed under the Clean Air Act.

(4) United States substantive and procedural laws shall apply to any civil or criminal enforcement action against the foreign RIN owner or any employee of the foreign RIN owner related to the provisions of this section.

(5) Submitting an application to be a foreign RIN owner, and all other actions to comply with the requirements of this subpart constitute actions or activities covered by and within the meaning of the provisions of 28 U.S.C. 1605(a)(2), but solely with respect to actions instituted against the foreign RIN owner, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign RIN owner under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(6) The foreign RIN owner, or its agents or employees, will not seek to detain or to impose civil or criminal remedies against EPA inspectors or auditors, whether EPA employees or EPA contractors, for actions performed within the scope of EPA employment related to the provisions of this section.

(7) The commitment required by this paragraph (c) shall be signed by the owner or president of the foreign RIN owner business.

(d) *Sovereign immunity*. By submitting an application to be a foreign RIN owner under this subpart, the foreign entity, and its agents and employees, without exception, become subject to the full operation of the administrative and judicial enforcement powers and provisions of the United States without limitation based on sovereign immunity, with respect to actions instituted against the foreign RIN owner, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign RIN owner under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(e) *Bond posting*. Any foreign entity shall meet the requirements of this paragraph (e) as a condition to approval as a foreign RIN owner under this subpart.

(1) The foreign entity shall post a bond of the amount calculated using the following equation:

$$\text{Bond} = G * \$\,0.01$$

Where:

Bond = amount of the bond in U.S. dollars.

G = the total of the number of gallon-RINs the foreign entity expects to sell or transfer during the first calendar year that the foreign entity is a RIN owner, plus the number of gallon-RINs the foreign entity expects to sell or transfer during the next four calendar years. After the first calendar year, the bond amount shall be based on the actual number of gallon-RINs sold or transferred during the current calendar year and the number held at the conclusion of the current averaging year, plus the number of gallon-RINs sold or transferred during the four most recent calendar years preceding the current calendar year. For any year for which there were fewer than four preceding years in which the foreign entity sold or transferred RINs, the bond shall be based on the total of the number of gallon-RINs sold or transferred during the current calendar year and the number held at the end of the current calendar year, plus the number of gallon-RINs sold or transferred during any calendar year preceding the current calendar year, plus the number of gallon-RINs expected to be sold or transferred during subsequent calendar years, the total number of years not to exceed four calendar years in addition to the current calendar year.

(2) Bonds shall be posted by doing any of the following:

(i) Paying the amount of the bond to the Treasurer of the United States.

(ii) Obtaining a bond in the proper amount from a third party surety agent that is payable to satisfy United States administrative or judicial judgments against the foreign RIN owner, provided EPA agrees in advance as to the third party and the nature of the surety agreement.

(iii) An alternative commitment that results in assets of an appropriate liquidity and value being readily available to the United States, provided EPA agrees in advance as to the alternative commitment.

(3) All the following shall apply to bonds posted under this paragraph (e); bonds shall:

(i) Be used to satisfy any judicial judgment that results from an administrative or judicial enforcement action for conduct in violation of this subpart, including where such conduct violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(ii) Be provided by a corporate surety that is listed in the United States Department of Treasury Circular 570 ''Companies Holding Certificates of Authority as Acceptable Sureties on Federal Bonds''.

(iii) Include a commitment that the bond will remain in effect for at least five years following the end of latest reporting period in which the foreign RIN owner obtains, sells, transfers, or holds RINs.

(4) On any occasion a foreign RIN owner bond is used to satisfy any judgment, the foreign RIN owner shall increase the bond to cover the amount

used within 90 days of the date the bond is used.

(f) *English language reports.* Any document submitted to EPA by a foreign RIN owner shall be in English, or shall include an English language translation.

(g) *Prohibitions.* (1) A foreign RIN owner is prohibited from obtaining, selling, transferring, or holding any RIN that is in excess of the number for which the bond requirements of this section have been satisfied.

(2) Any RIN that is sold, transferred, or held that is in excess of the number for which the bond requirements of this section have been satisfied is an invalid RIN under § 80.1431.

(3) Any RIN that is obtained from a party located outside the United States that is not an approved foreign RIN owner under this section is an invalid RIN under § 80.1431.

(4) No foreign RIN owner or other party may cause another party to commit an action prohibited in this paragraph (g), or that otherwise violates the requirements of this section.

(h) *Additional attest requirements for foreign RIN owners.* The following additional requirements apply to any foreign RIN owner as part of the attest engagement required for RIN owners under this subpart M.

(i) The attest auditor must be independent of the foreign RIN owner.

(ii) The attest auditor must be licensed as a Certified Public Accountant in the United States and a citizen of the United States, or be approved in advance by EPA based on a demonstration of ability to perform the procedures required in §§ 80.125 through 80.127, 80.130, and 80.1464.

(iii) The attest auditor must sign a commitment that contains the provisions specified in paragraph (c) of this section with regard to activities and documents relevant to compliance with the requirements of §§ 80.125 through 80.127, 80.130, and 80.1464.

(i) *Withdrawal or suspension of foreign RIN owner status.* EPA may withdraw or suspend its approval of a foreign RIN owner where any of the following occur:

(1) A foreign RIN owner fails to meet any requirement of this section, including, but not limited to, the bond requirements.

(2) A foreign government fails to allow EPA inspections as provided in paragraph (c)(1) of this section.

(3) A foreign RIN owner asserts a claim of, or a right to claim, sovereign immunity in an action to enforce the requirements in this subpart.

(4) A foreign RIN owner fails to pay a civil or criminal penalty that is not satisfied using the foreign RIN owner bond specified in paragraph (e) of this section.

(j) *Additional requirements for applications, reports and certificates.* Any application for approval as a foreign RIN owner, any report, certification, or other submission required under this section shall be:

(1) Submitted in accordance with procedures specified by the Administrator, including use of any forms that may be specified by the Administrator.

(2) Signed by the president or owner of the foreign RIN owner company, or by that party's immediate designee, and shall contain the following declaration:

''I hereby certify: 1) That I have actual authority to sign on behalf of and to bind [insert name of foreign RIN owner] with regard to all statements contained herein; 2) that I am aware that the information contained herein is being Certified, or submitted to the United States Environmental Protection Agency, under the requirements of 40 CFR part 80, subpart M, and that the information is material for determining compliance under these regulations; and 3) that I have read and understand the information being Certified or submitted, and this information is true, complete and correct to the best of my knowledge and belief after I have taken reasonable and appropriate steps to verify the accuracy thereof. I affirm that I have read and understand the provisions of 40 CFR part 80, subpart M, including 40 CFR 80.1467 apply to [insert name of foreign RIN owner]. Pursuant to Clean Air Act section 113(c) and 18 U.S.C. 1001, the penalty for furnishing false, incomplete or misleading information in this certification or submission is a fine of up to $10,000 U.S., and/or imprisonment for up to five years.''.

§ 80.1468 [Reserved]

§ 80.1469 What are the labeling requirements that apply to retailers and wholesale purchaser-consumers of ethanol fuel blends that contain greater than 10 volume percent ethanol?

(a) Any retailer or wholesale purchaser-consumer who sells, dispenses, or offers for sale or dispensing, ethanol fuel blends that contain greater than 10 volume percent ethanol must prominently and conspicuously display in the immediate area of each pump stand from which such fuel is offered for sale or dispensing, the following legible label in block letters of no less than 24-point bold type in a color contrasting with the background:

CONTAINS MORE THAN 10 VOLUME PERCENT ETHANOL

For use only in flexible-fuel gasoline vehicles.

May damage non-flexible fuel vehicles.

WARNING

Federal law prohibits use in non-flexible fuel vehicles.

(b) Alternative labels to those specified in paragraph (a) of this section may be used as approved by EPA. Requests for approval of alternative labels shall be sent to one of the following addresses:

(1) *For US mail:* U.S. EPA, *Attn:* Alternative fuel dispenser label request, 6406J, 1200 Pennsylvania Avenue, NW., Washington, DC 20460.

(2) *For overnight or courier services:* U.S. EPA, *Attn:* Alternative fuel dispenser label request, 6406J, 1310 L Street, NW., 6th floor, Washington, DC 20005. (202) 343–9038.

[FR Doc. E9–10978 Filed 5–22–09; 8:45 am]

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Tuesday, May 26, 2009

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