ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 80

[EPA–HQ–OAR–2011–0542; FRL–9502–2]

RIN 2060–AR07

Regulation of Fuels and Fuel Additives: Identification of Additional Qualifying Renewable Fuel Pathways Under the Renewable Fuel Standard Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: EPA is issuing a direct final rule identifying additional fuel pathways that EPA has determined meet the biomass-based diesel, advanced biofuel or cellulosic biofuel lifecycle greenhouse gas (GHG) reduction requirements specified in Clean Air Act section 211(o), the Renewable Fuel Standard Program, as amended by the Energy Independence and Security Act of 2007 (EISA). This direct final rule describes EPA's evaluation of biofuels produced from camelina oil, energy cane, giant reed, and napiergrass; it also includes an evaluation of renewable gasoline and renewable gasoline blendstocks, as well as biodiesel from esterification, and clarifies our definition of renewable diesel. We are also finalizing two changes to regulation that were proposed on July 1, 2011(76 FR 38844). The first change adds ID letters to pathways to facilitate references to specific pathways. The second change adds ''rapeseed'' to the existing pathway for renewable fuel made from canola oil.

This direct final rule adds these pathways to Table in regulation as pathways which have been determined to meet one or more of the GHG reduction thresholds specified in CAA 211(o), and assigns each pathway a corresponding D-Code. It allows producers or importers of fuel produced pursuant to these pathways to generate Renewable Identification Numbers (RINs), providing that the fuel meets the other requirements specified in the RFS regulations to qualify it as renewable fuel.

DATES: This rule is effective on March 5, 2012 without further notice, unless EPA receives adverse comment or a hearing request by February 6, 2012. If EPA receives a timely adverse comment or a hearing request, we will publish a withdrawal in the **Federal Register** informing the public that the portions of the rule with adverse comment will not take effect.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2011–0542, by one of the following methods:

- *www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *Email: a-and-r-docket@epa.gov,* Attention Air and Radiation Docket ID EPA–HQ–OAR–2011–0542
- *Fax:* [Insert fax number].
- *Mail:* Air and Radiation Docket, Docket No. EPA–HQ–OAR–2011–0542, Environmental Protection Agency, Mailcode: 6406J, 1200 Pennsylvania Ave. NW., Washington, DC 20460.
- *Hand Delivery:* EPA Docket Center, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave. NW., Washington, DC, 20460, Attention Air and Radiation Docket, ID No. EPA–HQ–OAR–2011–0542. 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–2011–0542. 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 email. 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 email comment directly to EPA without going through *www.regulations.gov* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

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).

FOR FURTHER INFORMATION CONTACT: Vincent Camobreco, Office of Transportation and Air Quality (MC6401A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460; telephone number: (202) 564–9043; fax number: (202) 564–1686; email address: *camobreco.vincent@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Why is EPA using a direct final rule?

EPA is publishing this rule without a prior proposed rule because we view this as a noncontroversial action. These new pathway determinations did not require new agricultural sector modeling and involved relatively straightforward analyses that largely relied upon work done for the RFS2 final rule. If EPA receives relevant adverse comment or a hearing request on a distinct provision of this rulemaking, we will publish a timely withdrawal in the **Federal Register** indicating which portion of the rule is being withdrawn. Any distinct amendment, paragraph, or section of today's rule not withdrawn will become effective on the date set out above.

In the ''Proposed Rules'' section of today's **Federal Register**, we are publishing a separate document that will serve as the proposed rule to update Table 1 of § 80.1426 to add any additional renewable fuel production pathways or regulatory provisions which may be withdrawn from the direct final rule. We will not institute a second comment period on this action. Any parties interested in commenting must do so at this time. For further information about commenting on this rule, see the **ADDRESSES** section of this document. We will address all public

comments in any subsequent final rule based on the proposed rule.

II. Does this action apply to me?

Entities potentially affected by this action 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 and entities affected by this action 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 action. This table lists the types of entities that EPA is now aware could be potentially regulated by this action. Other types of entities not listed in the table could also be regulated. To determine whether your entity is regulated by this action, you should carefully examine the applicability criteria of Part 80, subparts D, E and F of title 40 of the Code of Federal Regulations. If you have any question regarding applicability of this action to a particular entity, consult the person in the preceding **FOR FURTHER INFORMATION CONTACT** section above.

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

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

B. *Tips for Preparing Your Comments.* When submitting comments, remember to:

- Identify the rulemaking by docket number and other identifying information (subject heading, **Federal Register** date and page number).
- Follow directions—The agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.
- Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.
- Describe any assumptions and provide any technical information and/or data that you used.
- If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.
- Provide specific examples to illustrate your concerns, and suggest alternatives.
- Explain your views as clearly as possible, avoiding the use of profanity or personal threats.
- Make sure to submit your comments by the comment period deadline identified.

C. *Docket Copying Costs.* You may be charged a reasonable fee for photocopying docket materials, as provided in 40 CFR part 2.

IV. Identification of additional qualifying renewable fuel pathways under the renewable fuel standard (RFS) program

EPA is issuing a direct final rule to identify in the RFS regulations additional renewable fuel production pathways that we have determined meet the greenhouse gas (GHG) reduction requirements of the RFS program. This direct final rule describes EPA's evaluation of:

Camelina Oil (New Feedstock)

- Biodiesel and renewable diesel (including jet fuel and heating oil) — *qualifying as biomass-based diesel and advanced biofuel*
- Naphtha and liquefied petroleum gas (LPG) — *qualifying as advanced biofuel*

Energy Cane, Giant Reed, and Napiergrass Cellulosic Biomass (New Feedstocks)

- Ethanol, renewable diesel (including renewable jet fuel and heating oil), and naphtha — *qualifying as cellulosic biofuel*

Renewable Gasoline and Renewable Gasoline Blendstock (New Fuel Types)

- Produced from crop residue, slash, pre-commercial thinnings, tree residue, annual cover crops, and cellulosic components of separated yard waste, separated food waste, and separated municipal solid waste (MSW)
- Using the following processes — all utilizing natural gas, biogas, and/or biomass as the only process energy sources — *qualifying as cellulosic biofuel:*
  - Thermochemical pyrolysis
  - Thermochemical gasification
  - Biochemical direct fermentation
  - Biochemical fermentation with catalytic upgrading
  - Any other process that uses biogas and/or biomass as the only process energy sources

Esterification (New Production Process)

- Process used to produce biodiesel from soy bean oil, oil from annual covercrops, algal oil, biogenic waste oils/fats/greases, non-food grade corn oil, Canola/rapeseed oil, and camelina oil—*qualifying as biomass-based diesel and advanced biofuel*

This direct final rule adds these pathways to Table 1 to § 80.1426 and assigns each pathway one or more D–Codes. This final rule allows producers or importers of fuel produced under these pathways to generate Renewable Identification Numbers (RINs) in accordance with the RFS regulations, providing that the fuel meets other definitional criteria for renewable fuel.

Determining whether a fuel pathway satisfies the CAA's lifecycle GHG

reduction thresholds for renewable fuels requires a comprehensive evaluation of the lifecycle GHG emissions of the renewable fuel as compared to the lifecycle GHG emissions of the baseline gasoline or diesel fuel that it replaces. As mandated by CAA section 211(o), the GHG emissions assessments must evaluate the aggregate quantity of GHG emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes) related to the full fuel lifecycle, including all stages of fuel and feedstock production, distribution, and use by the ultimate consumer.

In examining the full lifecycle GHG impacts of renewable fuels for the RFS program, EPA considers the following:

- Feedstock production—based on agricultural sector models that include direct and indirect impacts of feedstock production
- Fuel production—including process energy requirements, impacts of any raw materials used in the process, and benefits from co-products produced.
- Fuel and feedstock distribution—including impacts of transporting feedstock from production to use, and transport of the final fuel to the consumer.
- Use of the fuel—including combustion emissions from use of the fuel in a vehicle.

Many of the pathways evaluated in this rulemaking rely on a comparison to the lifecycle GHG analysis work that was done as part of the Renewable Fuel Standard Program (RFS2) Final Rule, published March 26, 2010. The evaluations here rely on comparisons to the existing analysis. EPA plans to periodically review and revise the methodology and assumptions associated with calculating the GHG emissions from all renewable fuel pathways.

A. Analysis of Lifecycle Greenhouse Gas Emissions for Biodiesel, Renewable Diesel, Jet Fuel, Naphtha, and Liquefied Petroleum Gas (LPG) Produced From Camelina Oil

1. Feedstock Production

Camelina sativa (camelina) is an oilseed crop within the flowering plant family Brassicaceae that is native to Northern Europe and Central Asia. Camelina's suitability to northern climates and low moisture requirements allows it to be grown in areas that are unsuitable for other major oilseed crops such as soybeans, sunflower, and canola/rapeseed. Camelina also requires the use of little to no tillage.[1] Compared to many other oilseeds, camelina has a relatively short growing season (less than 100 days), and can be grown either as a spring annual or in the winter in milder climates. [2] [3] Camelina can also be used to break the continuous planting cycle of certain grains, effectively reducing the disease, insect, and weed pressure in fields planted with such grains (like wheat) in the following year.[4]

Although camelina has been cultivated in Europe in the past for use as food, medicine, and as a source for lamp oil, commercial production using modern agricultural techniques has been limited.[5] In addition to being used as a renewable fuel feedstock, small quantities of camelina (less than 5% of total U.S. camelina production) are currently used as a dietary supplement and in the cosmetics industry. Approximately 95% of current US production of camelina has been used for testing purposes to evaluate its use as a feedstock to produce primarily jet fuel.[6] The FDA has not approved camelina for food uses, although it has approved the inclusion of certain quantities of camelina meal in commercial feed.[7]

Camelina is currently being grown on approximately 50,000 acres of land in the U.S., primarily in Montana, eastern Washington, and the Dakotas.[8] USDA does not systematically collect camelina production information; therefore data on historical acreage is limited. However, available information indicates that camelina has been grown on trial plots in 12 U.S. states.[9]

For the purposes of analyzing the lifecycle GHG emissions of camelina, EPA has considered the likely production pattern for camelina grown for biofuel production. Given the information currently available, camelina is expected to be primarily planted in the U.S. as a rotation crop on acres that would otherwise remain fallow during the camelina planting. Since substituting fallow land with camelina production would not typically displace another crop, EPA does not believe new acres would need to be brought into agricultural use to increase camelina production. In addition, camelina currently has only limited high-value niche markets for uses other than renewable fuels. Unlike commodity crops that are tracked by USDA, camelina does not have a well-established, internationally traded market that would be significantly affected by an increase in the use of camelina to produce biofuels. For these reasons, which are described in more detail below, EPA has determined that production of camelina-based biofuels is not expected to result in significant GHG emissions related to direct land use change since it is grown on fallow land. Furthermore, due to the limited non-biofuel uses for camelina, production of camelina-based biofuels is not expected to have a significant impact on other agricultural crop production or commodity markets (either camelina or other crop markets) and consequently would not result in significant GHG emissions related to indirect land use change. To the extent camelina-based biofuel production decreases the demand for alternative biofuels, some with higher GHG emissions, this biofuel could have some beneficial GHG impact. However, it is uncertain which mix of biofuel sources the market will demand so this potential GHG impact cannot be quantified.

a. Growing Practices

Current market conditions indicate that camelina will most likely be grown in rotation with wheat on dryland wheat acres replacing a period that they would otherwise be left fallow.[10] In areas with lower precipitation, dryland wheat farmers currently leave acres fallow once every three to four years to allow additional moisture and nutrients to accumulate and to control pests. Current research indicates that camelina could be introduced into this rotation in certain areas without adversely impacting moisture or nutrient accumulation (see Figure 1). Because camelina has shallow roots with drought resistant characteristics, the

[1] Putnam, D.H., J.T. Budin, L.A. Field, and W.M. Breene. 1993. Camelina: A promising low-input oilseed. p. 314–322. In: J. Janick and J.E. Simon (eds.), New crops. Wiley, New York.

[2] Moser, B.R., Vaughn, S.F. 2010. Evaluation of Alkyl Esters from Camelina Sativa Oil as Biodiesel and as Blend Components in Ultra Low Sulfur Diesel Fuel. Bioresource Technology. 101:646–653.

[3] McVay, K.A., and P.F. Lamb. 2008. Camelina production in Montana. MSU Ext. MT200701AG (revised). http://msuextension.org/publica–tions/AgandNaturalResources/MT200701AG.pdf.

[4] Putnam *et al.,* 1993.

[5] Lafferty, Ryan M., Charlie Rife and Gus Foster. 2009. Spring camelina production guide for the Central High Plains. Blue Sun Biodiesel special publication. Blue Sun Agriculture Research & Development, Golden, CO. *http://www.gobluesun.com/upload/Spring%20Camelina%20Production%20Guide%202009.pdf.*

[6] Telephone conversation with Scott Johnson, Sustainable Oils, January 11, 2011.

[7] See *http://agr.mt.gov/camelina/FDAletter11–09.pdf.*

[8] McCormick, Margaret. ''Oral Comments of Targeted Growth, Incorporated'' Submitted to the EPA on June 9, 2009.

[9] See *https://www.camelinacompany.com/Marketing/PressRelease.aspx?Id=25.*

[10] See Shonnard, D. R., Williams, L., & Kalnes, T. N. 2010. Camelina-Derived Jet Fuel and Diesel: Sustainable Advanced Biodiesel. *Environmental Progress & Sustainable Energy,* 382–392.

land can be returned to wheat cultivation the following year with moisture and soil nutrients intact quantitatively similar to a fallow year.[11]

[11] See Shonnard *et al.,* 2010; Lafferty *et al.,* 2009.

In addition, camelina uses the same equipment for harvesting as wheat; therefore, farmers would not need to invest in new equipment to add camelina to the rotation with wheat.[12]

[12] Wheeler, P and F. Guillen-Portal. 2007. Camelina Production in Montana: A survey study sponsored by Targeted Growth, Inc. and Barkley Ag. Enterprises, LLP (unpublished).

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Figure 1: Examples of Traditional Wheat and Camelina/Wheat Rotations

Example 1: Traditional Winter Wheat/Spring Wheat/Fallow Rotation

	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Year 0										Winter Wheat Planting		
Year 1								Winter Wheat Harvest				
Year 2				Spring Wheat Planting				Spring Wheat Harvest				
Year 3										Winter Wheat Planting		

Example 2: Winter Wheat/Camelina/Spring Wheat Rotation

	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Year 0										Winter Wheat Planting		
Year 1								Winter Wheat Harvest				
Year 2				Camelina Planting				Camelina Harvest				
Year 3				Spring Wheat Planting				Spring Wheat Harvest		Winter Wheat Planting		

Shaded cells indicate fallow months

Hatched line cells indicate growing moths

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b. Land Availability

USDA estimates that there are approximately 60 million acres of wheat in the U.S.[13] USDA and wheat state cooperative extension reports through 2008 indicate that 83% of U.S. wheat production is under non-irrigated, dryland conditions. Of the approximately 50 million non-irrigated acres, at least 45% are estimated to follow a wheat/fallow rotation. Thus, approximately 22 million acres are potentially suitable for camelina production. However, according to industry projections, only about 9 million of these wheat/fallow acres have the appropriate climate, soil profile, and market access for camelina production.[14] Therefore, our analysis uses the estimate that only 9 million wheat/fallow acres are available for camelina production.

c. Projected Volumes

Based on these projections of land availability, EPA estimates that at current yields (approximately 800 pounds per acre), approximately 100 million gallons (MG) of camelina-based renewable fuels could be produced with camelina grown in rotation with existing crop acres without having direct land use change impacts. Also, since camelina will likely be grown on fallow land and thus not displace any other crop and since camelina currently does not have other significant markets, expanding production and use of camelina for biofuel purposes is not likely to have other agricultural market impacts and therefore, would not result in any significant indirect land use impacts.[15] This assessment is based on a three year rotation cycle in which only one third of the 9 million available acres would be fallow in any given year. Yields of camelina are expected to approach the yields of similar oilseed crops over the next few years, as experience with growing camelina improves cultivation practices and the application of existing technologies are more widely adopted.[16] Yields of 1650 pounds per acre have been achieved on test plots, and are in line with expected yields of other oilseeds such as canola/rapeseed. Assuming average US yields of 1650 pounds per acre,[17] approximately 200 MG of camelina-based renewable fuels could be produced on existing wheat/fallow acres. Finally, if investment in new seed technology allows yields to increase to levels assumed by Shonnard *et al* (3000 pounds per acre), approximately 400 MG of camelina-based renewable fuels could be produced on existing acres.[18] Depending on future crop yields, we project that roughly 100 MG to 400 MG of camelina-based biofuels could be produced on currently fallow land with no impacts on land use.[19]

d. Indirect Impacts

Although wheat can in some cases be grown in rotation with other crops such as lentils, flax, peas, garbanzo, and millet, cost and benefit analysis indicate that camelina is most likely to be planted on soil with lower moisture and nutrients where other rotation crops are not viable.[20] Because expected returns on camelina are relatively uncertain, farmers are not expected to grow camelina on land that would otherwise be used to grow cash crops with well established prices and markets. Instead, farmers are most likely to grow camelina on land that would otherwise be left fallow for a season. The opportunity cost of growing camelina on this type of land is much lower. As previously discussed, this type of land represents the 9 million acres currently being targeted for camelina production. Current returns on camelina are relatively low ($13.24 per acre), given average yields of approximately 800 pounds per acre and the current contract price of $0.145 per pound.[21] See Table 1. For comparison purposes, the USDA projections for wheat returns are between $88–$105 per acre between 2010 and 2020. Over time, advancements in seed technology, improvements in planting and harvesting techniques, and higher input usage could significantly increase future camelina yields and returns.

TABLE 1—CAMELINA COSTS AND RETURNS

Inputs	Rates	2010 Camelina [22]	2022 Camelina [23]	2030 Camelina [24]
Herbicides:				
Glysophate (Fall)	16 oz. ($0.39/oz)	$7.00	$7.00	$7.00.
Glysophate (Spring)	16 oz. ($0.39/oz)	$7.00	$7.00	$7.00.
Post	12 oz ($0.67/oz)	$8.00	$8.00	$8.00.
Seed:				
Camelina seed	$1.44/lb	$5.76 (4 lbs/acre)	$7.20 (5 lbs/acre)	$7.20 (5 lbs/acre).
Fertilizer:				
Nitrogen Fertilizer	$1/pd	$25.00 (25 lb/acre)	$40.00 (40 lb/acre)	$75 (75 lbs/acre).
Phosphate Fertilizer	$1/pd	$15.00 (15 lb/acre)	$15.00 (15 lb/acre)	$15 (15 lb/acre).
Sub-Total		$67.76	$84.20	$119.20.
Logistics:				
Planting Trip		$10.00	$10.00	$10.00.
Harvest & Hauling		$25.00	$25.00	$25.00.

[13] 2009 USDA Baseline. See *http://www.ers.usda.gov/publications/oce091/.*

[14] Johnson, S. and McCormick, M., Camelina: an Annual Cover Crop Under 40 CFR Part 80 Subpart M, Memorandum, dated November 5, 2010.

[15] Wheeler, P. and Guillen-Portal F. 2007. Camelina Production in Montana: A survey study sponsored by Targeted Growth, Inc. and Barkley Ag. Enterprises, LLP.

[16] See Hunter, J and G. Roth. 2010. Camelina Production and Potential in Pennsylvania, Penn State University Agronomy Facts 72. See *http://pubs.cas.psu.edu/freepubs/pdfs/uc212.pdf.*

[17] Ehrensing, D.T. and S.O. Guy. 2008. Oilseed Crops—Camelina. Oregon State Univ. Ext. Serv. EM8953–E. See *http://extension.oregonstate.edu/catalog/pdf/em/em8953-e.pdf;* McVay & Lamb, 2008.

[18] See Shonnard *et al.,* 2010.

[19] This assumes no significant adverse climate impacts on world agricultural yields over the analytical timeframe.

[20] See Lafferty *et al.,* 2009; Shonnard *et al.,* 2010; Sustainable Oils Memo dated November 5, 2010,

[21] Wheeler & Guillen-Portal, 2007.

[22] See Sustainable Oils Memo dated November 5, 2010,

[23] Based on yields technically feasible. See McVey and Lamb, 2008; Ehrenson & Guy, 2008.

[24] Adapted from Shonnard *et al,* 2010.

TABLE 1—CAMELINA COSTS AND RETURNS—Continued

Inputs	Rates	2010 Camelina [22]	2022 Camelina [23]	2030 Camelina [24]
Total Cost		$102.76	$119.20	$154.20.
Yields	lb/acre	800	1650	3000.
Price	$/lb	$0.145	$0.120	$0.090.
Total Revenue at avg prod/pricing		$116.00	$198	$270.
Returns		$13.24	$78.80	$115.80.

While replacing the fallow period in a wheat rotation is expected to be the primary means by which the majority of all domestic camelina is commercially harvested in the short- to medium- term, in the long term camelina may expand to other regions and growing methods.[25] For example, if camelina production expanded beyond the 9 million acres assumed available from wheat fallow land, it could impact other crops. However, as discussed above this is not likely to happen in the near term due to uncertainties in camelina financial returns. Camelina production could also occur in areas where wheat is not commonly grown. For example, testing of camelina production has occurred in Florida in rotation with kanaf, peanuts, cotton, and corn. However, only 200 acres of camelina were harvested in 2010 in Florida. While Florida acres of camelina are expected to be higher in 2011, very little research has been done on growing camelina in Florida. For example, little is known about potential seedling disease in Florida or how camelina may be affected differently than in colder climates.[26] Therefore, camelina grown outside of a wheat fallow situation was not considered as part of this analysis.

The determination in this final rule is based on our projection that camelina is likely to be produced on what would otherwise be fallow land. However, the rule applies to all camelina regardless of where it is grown. EPA does not expect that significant camelina would be grown on non-fallow land, and small quantities that may be grown elsewhere and used for biofuel production will not significantly impact our analysis.

Furthermore, although we expect most camelina used as a feedstock for renewable fuel production that would qualify in the RFS program would be grown in the U.S., today's rule would apply to qualifying renewable fuel made from camelina grown in any country. For the same reasons that pertain to U.S. production of camelina, we expect that camelina grown in other countries would also be produced on land that would otherwise be fallow and would therefore have no significant land use change impacts. The renewable biomass provisions under the Energy Independence and Security Act would prohibit direct land conversion into new agricultural land for camelina production for biofuel internationally. Additionally, any camelina production on existing cropland internationally would not be expected to have land use impacts beyond what was considered for international soybean production (soybean oil is the expected major feedstock source for U.S. biodiesel fuel production and thus the feedstock of reference for the camelina evaluation). Because of these factors along with the small amounts of fuel potentially coming from other countries, we believe that incorporating fuels produced in other countries will not impact our threshold analysis for camelina-based biofuels.

e. Crop Inputs

For comparison purposes, Table 2 shows the inputs required for camelina production compared to the FASOM agricultural input assumptions for soybeans. Since yields and input assumptions vary by region, a range of values for soybean production are shown in Table 2. The camelina input values in Table 2 represent average values, camelina input values will also vary by region, however, less data is available comparing actual practices by region due to limited camelina production. More information on camelina inputs is available in materials provided in the docket.

Table 2: Inputs for Camelina and Soybean Production

	Camelina			Soybeans (varies by region)						
	Inputs (per acre)		Emissions (per mmbtu fuel)	Inputs (per acre)			Emissions (per mmbtu fuel)			
N2O	N/A		22 kg CO2eq	N/A			9	-	12	kg CO2eq
Nitrogen Fertilizer	40	lbs	7 kg CO2eq	3.5 -	8.2	lbs	1	-	3	kg CO2eq
Phosphorus Fertilizer	15	lbs	1 kg CO2eq	5.4 -	21.4	lbs	0	-	2	kg CO2eq
Potassium Fertilizer	10	lbs	0 kg CO2eq	3.1 -	24.3	lbs	0	-	2	kg CO2eq
Herbicide	2.75	lbs	3 kg CO2eq	0.0 -	1.3	lbs	0	-	2	kg CO2eq
Pesticide	0	lbs	0 kg CO2eq	0.1 -	0.8	lbs	0	-	2	kg CO2eq
Diesel	3.5	gal	5 kg CO2eq	3.8 -	8.9	gal	7	-	20	kg CO2eq
Gasoline	0	gal	0 kg CO2eq	1.6 -	3.0	gal	3	-	5	kg CO2eq
Total			39 kg CO2eq				21	-	47	kg CO2eq

Regarding crop inputs per acre, it should be noted that camelina has a higher percentage of oil per pound of seed than soybeans. Soybeans are approximately 18% oil, therefore crushing one pound of soybeans yields

[25] See Sustainable Oils Memo dated November 5, 2010 for a map of the regions of the country where camelina is likely to be grown in wheat fallow conditions.

[26] Wright & Marois, 2011.

0.18 pounds of oil. In comparison, camelina is approximately 36% oil, therefore crushing one pound of camelina yields 0.36 pounds of oil. The difference in oil yield is taken into account when calculating the emissions per mmBTU included in Table 2. As shown in Table 2, GHG emissions from feedstock production for camelina and soybeans are relatively similar when factoring in variations in oil yields per acre and fertilizer, herbicide, pesticide, and petroleum use.

In summary, EPA concludes that the agricultural inputs for growing camelina are similar to those for growing soy beans, direct land use impact is expected to be negligible due to planting on land that would be otherwise fallow, and the limited production and use of camelina indicates no expected impacts on other crops and therefore no indirect land use impacts.

f. Crushing and Oil Extraction

We also looked at the seed crushing and oil extraction process and compared the lifecycle GHG emissions from this stage for soybean oil and camelina oil. As discussed above, camelina seeds produce more oil per pound than soybeans. As a result, the lifecycle GHG emissions associated with crushing and oil extraction are lower for camelina than soybeans, per pound of vegetable oil produced. Table 3 summarizes data on inputs, outputs and estimated lifecycle GHG emissions from crushing and oil extraction. The data on soybean crushing comes from the RFS2 final rule, based on a process model developed by USDA–ARS.[27] The data on camelina crushing is from Shonnard *et al.* (2010).

TABLE 3—COMPARISON OF CAMELINA AND SOYBEAN CRUSHING AND OIL EXTRACTION

Item	Soybeans	Camelina	Units
Material Inputs:			
Beans or Seeds	5.38	2.90	Lbs.
Energy Inputs:			
Electricity	374	47	Btu.
Natural Gas & Steam	1,912	780	Btu.
Outputs:			
Refined vegetable oil	1.00	1.00	Lbs.
Meal	4.08	1.85	Lbs.
GHG Emissions	213	64	gCO2e/lb refined oil.

2. Feedstock Distribution, Fuel Distribution, and Fuel Use

For this analysis, EPA projects that the feedstock distribution emissions will be the same for camelina and soybean oil. To the extent that camelina contains more oil per pound of seed, as discussed above, the energy needed to move the camelina would be lower than soybeans per gallon of fuel produced. To the extent that camelina is grown on more disperse fallow land than soybean and would need to be transported further, the energy needed to move the camelina could be higher than soybean. Based on this, we believe the assumption to use the same distribution impacts for camelina as soybean is a reasonable estimate of the GHG emissions from camelina feedstock distribution. In addition, the final fuel produced from camelina is also expected to be similar in composition to the comparable fuel produced from soybeans, therefore we are assuming GHG emissions from the distribution and use of fuels made from camelina will be the same as emissions of fuel produced from soybeans.

3. Fuel Production

There are two main fuel production processes used to convert camelina oil into fuel. The trans-esterification process produces biodiesel and a glycerin co-product. The hydrotreating process can be configured to produce renewable diesel either primarily as diesel fuel (including heating oil) or primarily as jet fuel. Possible additional products from hydrotreating include naphtha, LPG, and propane. Both processes and the fuels produced are described in the following sections. Both processes use camelina oil as a feedstock and camelina crushing is also included in the analysis.

a. Biodiesel

For this analysis, we assumed the same biodiesel production facility designs and conversion efficiencies as modeled for biodiesel produced from soybean oil and canola/rapeseed oil. Camelina oil biodiesel is produced using the same methods as soybean oil biodiesel, therefore plant designs are assumed to not significantly differ between fuels made from these feedstocks. As was the case for soybean oil biodiesel, we have not projected in our assessment of camelina oil biodiesel any significant improvements in plant technology. Unanticipated energy saving improvements would further improve GHG performance of the fuel pathway.

The glycerin produced from camelina biodiesel production is equivalent to the glycerin produced from the existing biodiesel pathways (*e.g.,* based on soy oil) that were analyzed as part of the RFS2 final rule. Therefore the same co-product credit would apply to glycerin from camelina biodiesel as glycerin produced in the biodiesel pathways modeled for the RFS2 final rule. The assumption is that the GHG reductions associated with the replacement of residual oil with glycerin on an energy equivalent basis represents an appropriate midrange co-product credit of biodiesel produced glycerin.

As part of our RFS2 proposal, we assumed the glycerin would have no value and would effectively receive no co-product credits in the soy biodiesel pathway. We received numerous comments, however, stating that the glycerin would have a beneficial use and should generate co-product benefits. Therefore, the biodiesel glycerin co-product determination made as part of the RFS2 final rule took into consideration the possible range of co-product credit results. The actual co-product benefit will be based on what products are replaced by the glycerin and what new uses develop for the co-product glycerin. The total amount of glycerin produced from the biodiesel industry will actually be used across a number of different markets with different GHG impacts. This could include for example, replacing

[27] A. Pradhan, D.S. Shrestha, A. McAloon, W. Yee, M. Haas, J.A. Duffield, H. Shapouri, September 2009, ''Energy Life-Cycle Assessment of Soybean Biodiesel'', United States Department of Agriculture, Office of the Chief Economist, Office of Energy Policy and New Uses, Agricultural Economic Report Number 845.

petroleum glycerin, replacing fuel products (residual oil, diesel fuel, natural gas, *etc.*), or being used in new products that don't have a direct replacement, but may nevertheless have indirect effects on the extent to which existing competing products are used. The more immediate GHG reduction credits from glycerin co-product use will likely range from fairly high reduction credits when petroleum glycerin is replaced to lower reduction credits if it is used in new markets that have no direct replacement product, and therefore no replaced emissions.

EPA does not have sufficient information (and received no relevant comments as part of the RFS2 rule) on which to allocate glycerin use across the range of likely uses. Therefore, EPA believes that the approach used in RFS2 of picking a surrogate use for modeling purposes in the mid-range of likely glycerin uses, and the GHG emissions results tied to such use, is reasonable. The replacement of an energy equivalent amount of residual oil is a simplifying assumption determined by EPA to reflect the mid-range of possible glycerin uses in terms of GHG credits. EPA believes that it is appropriately representative of GHG reduction credit across the possible range without necessarily biasing the results toward high or low GHG impact. Given the fundamental difficulty of predicting possible glycerin uses and impacts of those uses many years into the future under evolving market conditions, EPA believes it is reasonable to use the more simplified approach to calculating co-product GHG benefit associated with glycerin production.

Given the fact that GHG emissions from camelina-based biodiesel would be similar to the GHG emissions from soybean- based biodiesel at all stages of the lifecycle but would not result in land use change as was the case for soy oil used as a feedstock, we believe biodiesel from camelina oil will also meet the 50% GHG emissions reduction threshold to qualify as a biomass based diesel and an advanced fuel. Therefore, EPA is including biodiesel produced from camelina oil under the same pathways for which biodiesel made from soybean oil qualifies under the RFS2 final rule.

b. Renewable Diesel (Including Jet Fuel and Heating Oil), Naphtha, and LPG

The same feedstocks currently used for biodiesel production can also be used in a hydrotreating process to produce a slate of products, including diesel fuel, heating oil (defined as No. 1 or No. 2 diesel), jet fuel, naphtha, LPG, and propane. Since the term renewable diesel is defined to include the products diesel fuel, jet fuel and heating oil, the following discussion uses the term renewable diesel to also include diesel fuel, jet fuel and heating oil. The yield of renewable diesel is relatively insensitive to feedstock source.[28] While any propane produced as part of the hydrotreating process will most likely be combusted within the facility for process energy, the other co-products that can be produced (*i.e.,* renewable diesel, naphtha, LPG) are higher value products that could be used as transportation fuels or, in the case of naphtha, a blendstock for production of transportation fuel. The hydrotreating process maximized for producing a diesel fuel replacement as the primary fuel product requires more overall material and energy inputs than transesterification to produce biodiesel, but it also results in a greater amount of other valuable co-products as listed above. The hydrotreating process can also be maximized for jet fuel production which requires even more process energy than the process optimized for producing a diesel fuel replacement, and produces a greater amount of co-products per barrel of feedstock, especially naphtha.

Producers of renewable diesel from camelina have expressed interest in generating RINs under the RFS2 program for the slate of products resulting from the hydrotreating process. Our lifecycle analysis accounts for the various uses of the co-products. There are two main approaches to accounting for the co-products produced, the allocation approach, and the displacement approach. In the allocation approach all the emissions from the hydrotreating process are allocated across all the different co-products. There are a number of ways to do this but since the main use of the co-products would be to generate RINs as a fuel product we allocate based on the energy content of the co-products produced. In this case, emissions from the process would be allocated equally to all the Btus produced. Therefore, on a per Btu basis all co-products would have the same emissions. The displacement approach would attribute all of the emissions of the hydrotreating process to one main product and then account for the emission reductions from the other co-products displacing alternative product production. For example, if the hydrotreating process is configured to maximize diesel fuel replacement production, all of the emissions from the process would be attributed to diesel fuel, but we would then assume the other co-products were displacing alternative products, for example, naphtha would displace gasoline, LPG would displace natural gas, *etc.* This assumes the other alternative products are not produced or used, so we would subtract the emissions of gasoline production and use, natural gas production and use, *etc.* This would show up as a GHG emission credit associated with the production of diesel fuel replacement.

To account for the case where RINs are generated for the jet fuel, naphtha and LPG in addition to the diesel replacement fuel produced, we would not give the diesel replacement fuel a displacement credit for these co-products. Instead, the lifecycle GHG emissions from the fuel production processes would be allocated to each of the RIN-generating products on an energy content basis. This has the effect of tending to increase the fuel production lifecycle GHG emissions associated with the diesel replacement fuel because there are less co-product displacement credits to assign than would be the case if RINs were not generated for the co-products.[29] On the other hand, the upstream lifecycle GHG emissions associated with producing and transporting the plant oil feedstocks will be distributed over a larger group of RIN-generating products. Assuming each product (except propane) produced via the camelina oil hydrotreating process will generate RINs results in higher lifecycle GHG emissions for diesel fuel replacement as compared to the case where the co-products are not used to generate RINs. This general principle is also true when the hydrotreating process is maximized for jet fuel production. As a result, the worst GHG performance (*i.e.,* greatest lifecycle GHG emissions) for diesel replacement fuel and jet fuel produced from camelina oil via hydrotreating will occur when all of the co-products are RIN-generating (we assume propane will be used for process energy). Thus, if these fuels meet the 50% GHG reduction threshold for biomass based diesel or advanced biofuel when co-products are RIN-generating, they will

[28] Kalnes, T., N., McCall, M., M., Shonnard, D., R., 2010. Renewable Diesel and Jet-Fuel Production from Fats and Oils. Thermochemical Conversion of Biomass to Liquid Fuels and Chemicals, Chapter 18, p. 475.

[29] For a similar discussion see page 46 of Stratton, R.W., Wong, H.M., Hileman, J.I. 2010. Lifecycle Greenhouse Gas Emissions from Alternative Jet Fuels. PARTNER Project 28 report. Version 1.1. PARTNER–COE–2010–001. June 2010, *http://web.mit.edu/aeroastro/partner/reports/proj28/partner-proj28–2010–001.pdf.*

also do so in the case when RINs are not generated for co-products.

We have evaluated information about the lifecycle GHG emissions associated with the hydrotreating process which can be maximized for jet fuel or diesel replacement fuel production. Our evaluation considers information published in peer-reviewed journal articles and publicly available literature (Kalnes *et al,* 2010, Pearlson, M., N., 2011,[30] Stratton *et al.,* 2010, Huo *et al.,* 2008).[31] Our analysis of GHG emissions from the hydrotreating process is based on the mass and energy balance data in Pearlson (2011) which analyzes a hydrotreating process maximized for diesel replacement fuel production and a hydrotreating process maximized for jet fuel production.[32] This data is summarized in Table 4.

TABLE 4—HYDROTREATING PROCESSES TO CONVERT CAMELINA OIL INTO DIESEL REPLACEMENT FUEL AND JET FUEL[33]

	Maximized for diesel fuel production	Maximized for jet fuel production	Units (per gallon of fuel produced)
Inputs:			
Refined camelina oil	9.56	12.84	Lbs.
Hydrogen	0.04	0.08	Lbs.
Electricity	652	865	Btu.
Natural Gas	23,247	38,519	Btu.
Outputs:			
Diesel Fuel	123,136	55,845	Btu.
Jet fuel	23,197	118,669	Btu.
Naphtha	3,306	17,042	Btu.
LPG	3,084	15,528	Btu.
Propane	7,454	9,881	Btu.

Table 5 compares lifecycle GHG emissions from oil extraction and fuel production for soybean oil biodiesel and for camelina-based diesel and jet fuel. The lifecycle GHG estimates for camelina oil diesel and jet fuel are based on the input/output data summarized in Table 3 (for oil extraction) and Table 4 (for fuel production). We assume that the propane co-product does not generate RINs; instead, it is used for process energy displacing natural gas. We also assume that the naphtha is used as blendstock for production of transportation fuel to generate RINs. In this case we assume that RINs are generated for the use of LPG in a way that meets the EISA definition of transportation fuel, for example it could be used in a nonroad vehicle. The lifecycle GHG results in Table 5 represent the worst case scenario (*i.e.,* highest GHG emissions) because all of the eligible co-products are used to generate RINs. This is because, as discussed above, lifecycle GHG emissions per Btu of diesel or jet fuel would be lower if the naphtha or LPG is not used to generate RINs and is instead used for process energy displacing fossil fuel such as natural gas. Supporting information for the values in Table 5, including key assumptions and data, is provided through the docket.

TABLE 5—FUEL PRODUCTION LIFECYCLE GHG EMISSIONS (KGCO2e/MMBTU)[34]

Feedstock	Production process	RIN–Generating products	Other co-products	Oil extraction	Processing	Total
Soybean Oil	Trans-Esterification	Biodiesel	Glycerin	14	(1)	13
Camelina Oil	Trans-Esterification	Biodiesel	Glycerin	4	(1)	3
Camelina Oil	Hydrotreating Maximized for Diesel.	Diesel Jet Fuel. Naphtha. LPG.	Propane	4	8	12
Camelina Oil	Hydrotreating Maximized for Jet Fuel.	Jet Fuel Diesel. Naphtha. LPG.	Propane	4	11	14

As discussed above, for a process that produces more than one RIN-generating output (*e.g.,* the hydrotreating process summarized in Table 5 which produces diesel replacement fuel, jet fuel, and naphtha) we allocate lifecycle GHG emissions to the RIN generating products on an energy equivalent basis. We then normalize the allocated lifecycle GHG emissions per mmBtu of each fuel product. Therefore, each RIN-generating product from the same process will be assigned equal lifecycle GHG emissions per mmBtu from fuel processing. For example, based on the

[30] Pearlson, M., N. 2011. A Techno-Economic and Environmental Assessment of Hydroprocessed Renewable Distillate Fuels.

[31] Huo, H., Wang., M., Bloyd, C., Putsche, V., 2008. Life-Cycle Assessment of Energy and Greenhouse Gas Effects of Soybean-Derived Biodiesel and Renewable Fuels. Argonne National Laboratory. Energy Systems Division. ANL/ESD/08–2. March 12, 2008.

[32] We have also considered data submitted by companies involved in the hydrotreating industry which is claimed as confidential business information (CBI). The conclusions using the CBI data are consistent with the analysis presented here.

[33] Based on Pearlson (2011), Table 3.1 and Table 3.2.

[34] Lifecycle GHG emissions are normalized per mmBtu of RIN-generating fuel produced. Totals may not be the sum of the rows due to rounding error. Parentheses indicate negative numbers. Process emissions for biodiesel production are negative because they include the glycerin offset credit.

lifecycle GHG estimates in Table 5 for the hydrotreating process maximized to produce jet fuel, the jet fuel and the naphtha both have lifecycle GHG emissions of 14 $kgCO_2e$/mmBtu. For the same reasons, the lifecycle GHG emissions from the jet fuel and naphtha will stay equivalent if we consider upstream GHG emissions, such as emissions associated with camelina cultivation and harvesting. Lifecycle GHG emissions from fuel distribution and use could be somewhat different for the jet fuel and naphtha, but since these stages produce a relatively small share of the emissions related to the full fuel lifecycle, the overall difference will be quite small.

Given that GHG emissions from camelina oil would be similar to the GHG emissions from soybean oil at all stages of the lifecycle but would not result in land use change emissions (soy oil feedstock did have a significant land use change impact but still met a 50% GHG reduction threshold), and considering differences in process emissions between soybean biodiesel and camelina-based renewable diesel, we conclude that renewable diesel from camelina oil will also meet the 50% GHG emissions reduction threshold to qualify as biomass based diesel and advanced fuel. Although some of the potential configurations result in fuel production GHG emissions that are higher than fuel production GHG emissions for soybean oil biodiesel, land use change emissions account for approximately 80% of the soybean oil to biodiesel lifecycle GHGs. Since camelina is assumed not to have land use change emissions, our analysis shows that camelina renewable diesel will qualify for advanced renewable fuel and biomass-based diesel RINs even for the cases with the highest lifecycle GHGs (*e.g.,* when all of the co-products are used to generate RINs.) Because the lifecycle GHG emissions for RIN-generating co-products are very similar, we can also conclude naphtha and LPG produced from camelina oil will also meet the 50% GHG emissions reduction threshold. If the facility does not actually generate RINs for one or more of these co-products, we estimate that the lifecycle GHG emissions related to the RIN-generating products would be lower, thus renewable diesel (which includes diesel fuel, jet fuel, and heating oil) from camelina would still meet the 50% emission reduction threshold.

4. Summary

Current information suggests that camelina has limited niche markets and will be produced on land that would otherwise remain fallow. Therefore, increased production of camelina-based renewable fuel is not expected to result in significant land use change emissions. For the purposes of this analysis, EPA is projecting there will be no land use emissions associated with camelina production for use as a renewable fuel feedstock.

However, while production of camelina on acres that would otherwise remain fallow is expected to be the primary means by which the majority of all camelina is commercially harvested in the short- to medium- term, in the long term camelina may expand to other growing methods and lands if demand increases substantially beyond what EPA is currently predicting. While the impacts are uncertain, there are some indications demand could increase significantly. For example, camelina is included under USDA's Biomass Crop Assistance Program (BCAP) and there is growing support for the use of camelina oil in producing drop-in alternative aviation fuels. EPA plans to monitor the expansion of camelina production to verify whether camelina is primarily grown on existing acres once camelina is produced at larger-scale volumes. Similarly, we will consider market impacts if alternative uses for camelina expand significantly beyond what was described in the above analysis. Just as EPA plans to periodically review and revise the methodology and assumptions associated with calculating the GHG emissions from all renewable fuel feedstocks, EPA expects to review and revise as necessary the analysis of camelina in the future.

Taking into account the assumption of no land use change emissions when camelina is used to produce renewable fuel, and considering that other sources of GHG emissions related to camelina biodiesel or renewable diesel production have comparable GHG emissions to biodiesel from soybean oil, we have determined that camelina-based biodiesel and renewable diesel should be treated in the same manner as soy-based biodiesel and renewable diesel in qualifying as biomass-based diesel and advanced biofuel for purposes of RIN generation, since the GHG emission performance of the camelina-based fuels will be at least as good and in some respects better than that modeled for fuels made from soybean oil. EPA found as part of the Renewable Fuel Standard final rulemaking that soybean biodiesel resulted in a 57% reduction in GHG emissions compared to the baseline petroleum diesel fuel. Furthermore, approximately 80% of the lifecycle impacts from soybean biodiesel were from land use change emissions which are assumed to be not significant for the camelina pathway considered. Thus, EPA is including camelina oil as a potential feedstock under the same biodiesel and renewable diesel (which includes diesel fuel, jet fuel, and heating oil) pathways for which soybean oil currently qualifies. We are also including a pathway for naphtha and LPG produced from camelina oil through hydrotreating. This is based on the fact that our analysis shows that even when all of the co-products are used to generate RINs the lifecycle GHG emissions for RIN-generating co-products including diesel replacement fuel, jet fuel, naphtha and LPG produced from camelina oil will all meet the 50% GHG emissions reduction threshold.

We are also clarifying that two existing pathways for RIN generation in the RFS regulations that list ''renewable diesel'' as a fuel product produced through a hydrotreating process include jet fuel. This applies to two pathways in Table 1 to § 80.1426 of the RFS regulations which both list renewable diesel made from soy bean oil, oil from annual covercrops, algal oil, biogenic waste oils/fats/greases, or non-food grade corn oil using hydrotreating as a process. If parties produce jet fuel from the hydrotreating process and co-process renewable biomass and petroleum they can generate advanced biofuel RINs (D code 5) for the jet fuel produced. If they do not co-process renewable biomass and petroleum they can generate biomass-based diesel RINs (D code 4) for the jet fuel produced.

§ 80.1401 of the RFS regulations currently defines non-ester renewable diesel as a fuel that is not a mono-alkyl ester and which can be used in an engine designed to operate on conventional diesel fuel or be heating oil or jet fuel. The reference to jet fuel in this definition was added by direct final rule dated May 10, 2010. Table 1 to § 80.1426 identifies approved fuel pathways by fuel type, feedstock source and fuel production processes. The table, which was largely adopted as part of the March 26, 2010 RFS2 final rule, identifies jet fuel and renewable diesel as separate fuel types. Accordingly, in light of the revised definition of renewable diesel enacted after the RFS2 rule, there is ambiguity regarding the extent to which references in Table 1 to ''renewable diesel'' include jet fuel.

The original lifecycle analysis for the renewable diesel from hydrotreating pathways listed in Table 1 to § 80.1426 was not based on producing jet fuel but rather other transportation diesel fuel products, namely a diesel fuel replacement. As discussed above, the

hydrotreating process can produce a mix of products including jet fuel, diesel, naphtha, LPG and propane. Also, as discussed, there are differences in the process configured for maximum jet fuel production vs. the process maximized for diesel fuel production and the lifecycle results vary depending on what approach is used to consider co-products (*i.e.,* the allocation or displacement approach).

In cases where there are no pathways for generating RINs for the co-products from the hydrotreating process it would be appropriate to use the displacement method for capturing the credits of co-products produced. This is the case for most of the original feedstocks included in Table 1 to § 80.1426.[35] As was discussed previously, if the displacement approach is used when jet fuel is the primary product produced it results in lower emissions then the production maximized for diesel fuel production. Therefore, since the hydrotreating process maximized for diesel fuel meets the 50% lifecycle GHG threshold for the feedstocks in question, the process maximized for jet fuel would also qualify.

Thus, we are interpreting the references to ''renewable diesel'' in Table 1 to include jet fuel, consistent with our regulatory definition of ''non-ester renewable diesel,'' since doing so clarifies the existing regulations while ensuring that Table 1 to § 80.1426 appropriately identifies fuel pathways that meet the GHG reduction thresholds associated with each pathway.

We note that although the definition of renewable diesel includes jet fuel and heating oil, we have also listed in Table 1 of section 80.1426 of the RFS2 regulations jet fuel and heating oil as specific co-products in addition to listing renewable diesel to assure clarity. This clarification also pertains to all the feedstocks already included in Table 1 for renewable diesel.

B. Lifecycle Greenhouse Gas Emissions Analysis for Ethanol, Diesel, Jet Fuel, Heating Oil, and Naphtha Produced From Energy Cane, Giant Reed, and Napiergrass

For this rulemaking, EPA considered the lifecycle GHG impacts of three new types of high-yielding perennial grasses similar in cellulosic composition to switchgrass and comparable in status as an emerging energy crop. Energy cane (related to sugarcane), giant reed (*Arundo donax*), and napiergrass (*pennisetum purpureum*), also known as elephant grass. In the proposed and final RFS2 rule, EPA analyzed the lifecycle GHG impacts of producing and using cellulosic ethanol and cellulosic Fischer-Tropsch diesel from switchgrass. The midpoint of the range of switchgrass results showed a 110% GHG reduction (range of 102%–117%) for cellulosic ethanol (biochemical process), a 72% (range of −64% to −79%) reduction for cellulosic ethanol (thermochemical process), and a 71% (range of −62% to −77%) reduction for cellulosic diesel (F–T process) compared to the petroleum baseline. In the RFS2 final rule, we indicated that some feedstock sources can be determined to be similar enough to those modeled that the modeled results could reasonably be extended to these similar feedstock types. For instance, information on miscanthus indicated that this perennial grass will yield more feedstock per acre than the modeled switchgrass feedstock without additional inputs with GHG implications (such as fertilizer). Therefore in the final rule EPA concluded that since biofuel made from the cellulosic biomass in switchgrass was found to satisfy the 60% GHG reduction threshold for cellulosic biofuel, biofuel produced form the cellulosic biomass in miscanthus would also comply. In the final rule we included cellulosic biomass from switchgrass and miscanthus as eligible feedstocks for the cellulosic biofuel pathways included in Table 1 to § 80.1426.

We did not include other perennial grasses such as energy cane, giant reed, or napiergrass as feedstocks for the cellulosic biofuel pathways in Table 1 at that time, since we did not have sufficient time to adequately consider them. Based in part on additional information received through the petition process for EPA approval of energy cane, giant reed, and napiergrass pathways, EPA has evaluated these feedstocks and is now including the cellulose, hemicelluloses and lignin portions of renewable biomass from energy cane, giant reed, and napiergrass in Table 1 to § 80.1426 as approved feedstocks for cellulosic biofuel pathways.

As described in detail in the following sections of this preamble, because of the similarity of these feedstocks to switchgrass and miscanthus, EPA believes that new agricultural sector modeling is not needed to analyze them. We have instead relied upon the switchgrass analysis to assess the relative GHG impacts of biofuel produced from energy cane, giant reed, and napiergrass. As with the switchgrass analysis, we have attributed all land use impacts and resource inputs from use of these feedstocks to the portion of the fuel produced that is derived from the cellulosic components of the feedstocks. Based on this analysis and currently available information, we conclude that biofuel (ethanol, cellulosic diesel, jet fuel, heating oil and naptha) produced from the cellulosic biomass of energy cane, giant reed, or napiergrass has similar lifecycle GHG impacts to switchgrass biofuel and meets the 60% GHG reduction threshold required for cellulosic biofuel.

1. Feedstock Production and Distribution

For the purposes of this rulemaking, energy cane refers to varieties of perennial grasses in the *Saccharum* genus which are intentionally bred for high cellulosic biomass productivity but have characteristically low sugar content making them unsuitable as a primary source of sugar as compared to other varieties of grasses commonly known as ''sugarcane'' in the *Saccharum* genus. Energy cane varieties developed to date have low tolerance for cold temperatures but grow well in warm, humid climates. Energy cane originated from efforts to improve disease resistance and hardiness of commercial sugarcane by crossbreeding commercial and wild sugarcane strains. Certain higher fiber, lower sugar varieties that resulted were not suitable for commercial sugar production, and are now being developed as a high-biomass energy crop. There is currently no commercial production of energy cane. Current plantings are mainly limited to research field trials and small demonstrations for bioenergy purposes. However, based in part on discussions with industry, EPA anticipates continued development of energy cane particularly in the south-central and southeastern United States due to its high yields in these regions.

Giant reed refers to the perennial grass *Arundo donax* of the *Gramineae* family. Giant reed thrives in subtropical and warm-temperate areas and is grown throughout Asia, southern Europe, Africa, the Middle East, and warmer U.S. states for multiple uses such as paper and pulp, musical instruments, rayon, particle boards, erosion control, and ornamental purposes.[36] [37] Based in

[35] The exception is naphtha produced from waste categories, but these would pass the lifecycle thresholds regardless of the allocation approach used given their low feedstock GHG impacts.

[36] See *http://www.fs.fed.us/database/feis/plants/graminoid/arudon/all.html.*

[37] See Lewandowski, I., Scurlock, J.M.O., Lindvall, E., Christou, M. (2003). The development and current status of perennial rhizomatous grasses

Continued

part on discussions with industry, EPA anticipates continued development of giant reed as an energy crop particularly in the Mediterranean region and warmer U.S. states.

Napiergrass is a tall bunch-type grass that has traditionally been grown as a high-yielding forage crop across the wet tropics. There is a considerable body of agronomic research on the production of napiergrass as a forage crop. More recently, researchers have investigated ways to maximize traits desirable in bioenergy crops. Practices have been developed by USDA and other researchers to lower fertilization rates and increase biomass production. Based in part on discussions with industry, EPA anticipates continued development of napiergrass as an energy crop particularly in Gulf Coast Region of the United States (more specifically the growing region includes Florida and southern portions of Texas, Louisiana, Georgia, Alabama and Mississippi).[38]

a. Crop Yields

For the purposes of analyzing the GHG emissions from energy cane, giant reed, and napiergrass production, EPA examined crop yields and production inputs in relation to switchgrass to assess the relative GHG impacts. Current national yields for switchgrass are approximately 4.5 to 5 dry tons per acre. Average energy cane yields exceed switchgrass yields in both unfertilized and fertilized trails conducted in the southern United States. Unfertilized yields are around 7.3 dry tons per acre while fertilized trials show energy cane yields range from approximately 11 to 20 dry tons per acre.[39] [40] Until recently there have been few efforts to improve energy cane yields, but several energy cane development programs are now underway to further increase its biomass productivity. Giant reed field trials conducted in Alabama over a 9-year period showed an average yield of 15 dry tons per acre with no nitrogen fertilizer applied after the first year.[41] Fertilized field trials have shown yields around 13 to 28 dry tons per acre in Spain, and 12 dry tons per acre in Italy (based on annual yields of 3, 14, 17, 16, and 12).[42] High yields have been demonstrated with unimproved giant reed populations, and therefore there is potential for increased biomass productivity through improved growing methods and breeding efforts.[43] Napiergrass field trials have produced dry biomass yields exceeding 20 tons per acre per year in north-central Florida. Using currently available technology, average yields for full-season napiergrass should range from 14 to 18 tons per acre with future improvements expected. Yield depends greatly on the type of cultivar and the amount and distribution of rainfall and fertilization rates. There is potential for increased biomass productivity through improved growing methods and breeding efforts.[44] In general, the yields for all three of the energy grasses considered here will have higher yields than switchgrass, so from a crop yield perspective, the switchgrass analysis would be a conservative estimate when comparing against the energy cane, napier grass, and giant reed pathways.

Furthermore, EPA's analysis of switchgrass for the RFS2 rulemaking assumed a 2% annual increase in yield that would result in an average national yield of 6.6 dry tons per acre in 2022. EPA anticipates a similar yield improvement for energy cane, giant reed, and napiergrass due to their similarity as perennial grasses and their comparable status as energy crops in their early stages of development. Given this, our analysis assumes an average energy cane yield of 19 dry tons per acre in the southern United States by 2022; an average giant reed yield of approximately 18 dry tons per acre by 2022; and an average napiergrass yield of approximately 20 dry tons per acre by 2022.[45] The ethanol yield for all of the grasses is approximately the same so the higher crop yields for energy cane, napiergrass, and giant reed result directly in greater ethanol production compared to switchgrass per acre of production.

Based on these yield assumptions, in areas with suitable growing conditions, energy cane would require approximately 26% to 47% of the land area required by switchgrass to produce the same amount of biomass, giant reed would require less than 40% of the land area required by switchgrass to produce the same amount of biomass, and napiergrass would require approximately 33% of the land area required by switchgrass to produce the same amount of biomass due to their higher yields. Even without yield growth assumptions, their currently higher crop yield rates means the land use required for these crops would be lower than for switchgrass. Therefore less crop area would be converted and displaced resulting in smaller land-use change GHG impacts than that assumed for switchgrass to produce the same amount of fuel. Furthermore, we believe energy cane and napiergrass will have a similar impact on international markets as assumed for switchgrass. Like switchgrass, energy cane and napiergrass are not expected to be traded internationally and their impacts on other crops are expected to be limited. Increased giant reed demand in the U.S. for biofuels is not expected to impact existing markets for giant reed, which are relatively small niche markets (*e.g.,* musical instrument reeds).

b. Land Use

In EPA's RFS2 analysis, switchgrass plantings displaced primarily soybeans and wheat, and to a lesser extent hay, rice, sorghum, and cotton. Energy cane and napiergrass, with production focused in the southern United States, are likely to be grown on land once used for pasture, rice, commercial sod, cotton or alfalfa, which would likely have less of an international indirect impact than switchgrass because some of those commodities are not as widely traded as soybeans or wheat. Given that energy cane and napiergrass will likely displace the least productive land first, EPA concludes that the land use GHG impact for energy cane and napiergrass per gallon should be no greater and likely less than estimated for switchgrass. Given that giant reed is in early stages of development as an energy crop, there is limited information on where it will be grown and what crops it will displace. We expect giant reed will displace the least productive land first and would likely have a similar or smaller indirect impact associated with crop displacement than what we assumed for switchgrass.

Considering the total land potentially impacted by all the new feedstocks included in this rulemaking would not

as energy crops in the US and Europe. Biomass and Bioenergy 25, 335–361.

[38] For a map depicting the northern limit for sustained napiergrass production in the United States see Figure 1 in Woodard, K., R. and Sollenberger, L, E. 2008. Production of Biofuel Crops in Florida: Elephantgrass. Institute of Food and Agricultural Sciences, University of Florida. SS AGR 297.

[39] See Bischoff, K.P., Gravois, K.A., Reagan, T.E., Hoy, J.W., Kimbeng, C.A., LaBorde, C.M., Hawkins, G.L. *Plant Regis.* 2008, 2, 211–217.

[40] See Hale, A.L. *Sugar Bulletin,* 2010, 88, 28–29.

[41] Huang, P., Bransby, D., and Sladden, S. (2010). Exceptionally high yields and soil carbon sequestration recorded for giant reed in Alabama. Poster session presented at: ASA, CSSA, and SSSA 2010 International Annual Meetings, Green Revolution 2.0; 2010 Oct 31–Nov 4; Long Beach, CA.

[42] Mantineo, M., D'Agnosta, G.M., Copani, V., Patanè, C., and Cosentino, S.L. (2009). Biomass yield and energy balance of three perennial crops for energy use in the semi-arid Mediterranean environment. Field Crops Research 114, 204–213.

[43] Lewandowski *et al.* 2003.

[44] Based on discussions with industry and USDA and Woodard and Sollenberger (2008).

[45] These yields assume no significant adverse climate impacts on world agricultural yields over the analytical timeframe.

impact these conclusions (including the camelina discussed in the previous section and the three energy grasses considered here). As discussed previously, the camelina is expected to be grown on fallow land in the Northwest, while energy grasses are expected to be grown mainly in the south on existing cropland or pastureland. In the switchgrass ethanol scenario done for the Renewable Fuel Standard final rulemaking, total cropland acres increases by 4.2 million acres, including an increase of 12.5 million acres of switchgrass, a decrease of 4.3 million acres of soybeans, a 1.4 million acre decrease of wheat acres, a decrease of 1 million acres of hay, as well as decreases in a variety of other crops. Given the higher yields of the energy grasses considered here compared to switchgrass, there would be ample land available for production without having any adverse impacts beyond what was considered for switchgrass production.

c. Crop Inputs and Feedstock Transport

EPA also assessed the GHG impacts associated with planting, harvesting, and transporting energy cane, giant reed, and napiergrass feedstocks in comparison to switchgrass. Table 6 shows the assumed 2022 commercial-scale production inputs for switchgrass (used in the RFS2 rulemaking analysis), average energy cane, giant reed, and napiergrass production inputs (USDA projections and industry data) and the associated GHG emissions.

Available data gathered by EPA suggest that energy cane requires on average less nitrogen, phosphorous, potassium, and pesticide than switchgrass per dry ton of biomass, but more herbicide, lime, diesel, and electricity per unit of biomass. Giant reed may require on average less nitrogen and insecticide than switchgrass, but more phosphorous, potassium, herbicide, diesel, and electricity per unit of biomass. Napiergrass may require similar amounts of nitrogen fertilizer application as switchgrass, less phosphorous, potassium and insecticide than switchgrass, but more herbicide, lime, diesel, and electricity per unit of biomass.

This assessment assumes production of all three new feedstocks uses electricity for irrigation given that growers will likely irrigate when possible to improve yields. Irrigation rates will vary depending on the timing and amount of rainfall, but for the purpose of estimating GHG impacts of electricity use for irrigation, we assumed a rate similar to what we assumed for other irrigated crops in the Southwest, South Central, and Southeast as shown in Table 6.

Applying the GHG emission factors used in the RFS2 final rule, energy cane production results in slightly higher GHG emissions relative to switchgrass production (an increase of approximately 4 kg CO_2eq/mmbtu). Giant reed production results in slightly lower GHG emissions relative to switchgrass production (a decrease of approximately 2 kg CO_2eq/mmbtu). Napiergrass production results in slightly higher GHG emissions relative to switchgrass production (an increase of approximately 6 kg CO_2eq/mmbtu).

TABLE 6—PRODUCTION INPUTS AND GHG EMISSIONS FOR SWITCHGRASS, ENERGY CANE, GIANT REED, AND NAPIERGRASS (BIOCHEMICAL ETHANOL), 2022

	Emission factors	Switchgrass		Energy Cane		Giant Reed		Napiergrass	
		Inputs (per dry ton of biomass)	Emissions (per mmBtu fuel)	Inputs (per dry ton of biomass)	Emissions (per mmBtu fuel)	Inputs (per dry ton of biomass)	Emissions (per mmBtu fuel)	Inputs (per dry ton of biomass)	Emissions (per mmBtu fuel)
Nitrogen Fertilizer	3,29 kgCO_2e/ton of nitrogen.	15.2 lbs	3.6 kgCO_2e	8.4 lbs	2 kgCO_2e	5 lbs	1 kgCO_2e	10 lbs	2.4 kgCO_2e.
N_2O	N/A	N/A	7.6 kgCO_2e	N/A	5.9 kgCO_2e	N/A	4.8 kgCO_2e	N/A	7.6 kgCO_2e.
Phosphorus Fertilizer.	1,12 kgCO_2e/ton of phosphate.	6.1 lbs	0.5 kgCO_2e	3.2 lbs	0.3 kgCO_2e	7.4 lbs	0.6 kgCO_2e	1.1 lbs	0.1 kgCO_2e.
Potassium Fertilizer.	743 kgCO_2e/ton of potassium.	6.1 lbs	0.3 kgCO_2e	4.2 lbs	0.2 kgCO_2e	7.4 lbs	0.4 kgCO_2e	4.0 lbs	0.2 kgCO_2e.
Herbicide	23,45 kgCO_2e/ tons of herbicide.	0.002 lbs	0.003 kgCO_2e	1.0 lbs	1.8 kgCO_2e	0.02 lbs	0.03 kgCO_2e	0.4 lbs	0.6 kgCO_2e.
Insecticide (average across regions).	27,22 kgCO_2e/ tons of pesticide.	0.025 lbs	0.04 kgCO_2e	0 lbs	0 kgCO_2e	0 lbs	0 kgCO_2e	0 lbs	0 kgCO_2e.
Lime	408 kgCO_2e/ton of lime.	0 lbs	0 kgCO_2e	104.7 lbs	3.1 kgCO_2e	0 lbs	0 kgCO_2e	100 lbs	2.9 kgCO_2e.
Diesel	97 kgCO_2e/ mmBtu diesel.	0.4 gal	0.8 kgCO_2e	1.3 gal	2.4 kgCO_2e	1.4 gal	2.5 kgCO_2e	1.3 gal	2.2 kgCO_2e.
Electricity (irrigation).	220 kgCO_2e/ mmBtu.	0 kWh	0 kgCO_2e	14.7 kWh	1.6 kgCO_2e	10 kWh	1 kgCO_2e	25 kWh	2.7 kgCO_2e.
Total Emissions.			13 kgCO_2e/ mmBtu.		17 kgCO_2e/ mmBtu.		11 kgCO_2e/ mmBtu.		19 kgCO_2e/ mmBtu.

Assumes 2022 switchgrass yield of 6.59 dry tons/acre and 92.3 gal ethanol/dry ton, 2022 energy cane yield of 19.1 dry tons/acre and 92 gal ethanol/dry ton, 2022 giant reed yield of 18 dry tons/acre and 92.3 gal ethanol/dry ton, and 2022 napiergrass yield of 20 dry tons/acre and 92.3 gal ethanol/dry ton. More detail on calculations and assumptions is included in materials to the docket.

GHG emissions associated with distributing energy cane, giant reed, and napiergrass feedstocks are expected to be similar to EPA's estimates for switchgrass feedstock because they are all herbaceous agricultural crops requiring similar transport, loading, unloading, and storage regimes. Our analysis therefore assumes the same GHG impact for feedstock distribution as we assumed for switchgrass, although distributing energy cane, giant reed, and napiergrass feedstocks could be less GHG intensive because higher yields could translate to shorter overall hauling distances to storage or biofuel production facilities per gallon or Btu of final fuel produced.

2. Fuel Production, Distribution, and Use

Energy cane, giant reed, and napiergrass are suitable for the same conversion processes as other cellulosic

feedstocks, such as switchgrass and corn stover. Currently available information on energy cane, giant reed, and napiergrass composition shows that their hemicellulose, cellulose, and lignin content are comparable to other crops that qualify under the RFS regulations as feedstocks for the production of cellulosic biofuels. Based on this similar composition as well as conversion yield data provided by industry, we applied the same production processes that were modeled for switchgrass in the final RFS2 rule (biochemical ethanol, thermochemical ethanol, and Fischer-Tropsch (F–T) diesel [46]) to energy cane, giant reed, and napiergrass. We assumed the GHG emissions associated with producing biofuels from energy cane, giant reed, and napiergrass are similar to what we estimated for switchgrass and other cellulosic feedstocks. EPA also assumes that the distribution and use of biofuel made from energy cane, giant reed, and napiergrass will not differ significantly from similar biofuel produced from other cellulosic sources. As was done for the switchgrass case, this analysis assumes energy grasses grown in the United States for production purposes. If crops were grown internationally, used for biofuel production, and the fuel was shipped to the U.S., shipping the finished fuel to the U.S. could increase transport emissions. However, considering the increased transport emissions associated with sugarcane ethanol distribution to the U.S., this would at most add 1–2% to the overall lifecycle GHG impacts of the energy grasses.

3. Summary

Based on our comparison of switchgrass and the three feedstocks considered here, EPA believes that cellulosic biofuel produced from the cellulose, hemicellulose and lignin portions of energy cane, giant reed, and napiergrass has similar or better lifecycle GHG impacts than biofuel produced from the cellulosic biomass from switchgrass. Our analysis suggests that the three feedstocks considered have GHG impacts associated with growing and harvesting the feedstock that are similar to switchgrass. Emissions from growing and harvesting energy cane are approximately 4 kg CO2eq/mmBtu higher than switchgrass, emissions from growing and harvesting giant reed are approximately 2 kg CO2eq/mmBtu lower than switchgrass, and emissions from growing and harvesting napiergrass are approximately 6 kg CO2eq/mmBtu higher than switchgrass. These are small changes in the overall lifecycle, representing at most a 6% change in the energy grass lifecycle impacts in comparison to the petroleum fuel baseline. Furthermore, the three feedstocks considered are expected to have similar or lower GHG emissions than switchgrass associated with other components of the biofuel lifecycle.

Under a hypothetical worst case, if the calculated increases in growing and harvesting the new feedstocks are incorporated into the lifecycle GHG emissions calculated for switchgrass, and other lifecycle components are projected as having similar GHG impacts to switchgrass (including land use change associated with switchgrass production), the overall lifecycle GHG reductions for biofuel produced from energy cane, giant reed, and napiergrass still meet the 60% reduction threshold for cellulosic biofuel, the lowest being a 64% reduction (for napiergrass F–T diesel) compared to the petroleum baseline. We believe these are conservative estimates, as use of energy cane, giant reed, or napiergrass as a feedstock is expected to have smaller land-use GHG impacts than switchgrass, due to their higher yields. The docket for this rule provides additional detail on the analysis of energy cane, giant reed, and napiergrass as biofuel feedstocks.

Although this analysis assumes energy cane, giant reed, and napiergrass biofuels produced for sale and use in the United States will most likely come from domestically produced feedstock, we also intend for the approved pathways to cover energy cane, giant reed, and napiergrass from other countries. We do not expect incidental amounts of biofuels from feedstocks produced in other nations to impact our average GHG emissions. Moreover, those countries most likely to be exporting energy cane, giant reed, or napiergrass or biofuels produced from these feedstocks are likely to be major producers which typically use similar cultivars and farming techniques. Therefore, GHG emissions from producing biofuels with energy cane, giant reed, or napiergrass grown in other countries should be similar to the GHG emissions we estimated for U.S. energy cane, giant reed, or napiergrass, though they could be slightly (and insignificantly) higher or lower. For example, the renewable biomass provisions under the Energy Independence and Security Act would prohibit direct conversion of previously unfarmed land in other countries into cropland for energy grass-based renewable fuel production. Furthermore, any energy grass production on existing cropland internationally would not be expected to have land use impacts beyond what was considered for switchgrass production. Even if there were unexpected larger differences, EPA believes the small amounts of feedstock or fuel potentially coming from other countries will not impact our threshold analysis.

Based on our assessment of switchgrass in the RFS2 final rule and this comparison of GHG emissions from switchgrass and energy cane, giant reed, and napiergrass, we do not expect variations to be large enough to bring the overall GHG impact of fuel made from energy cane, giant reed or napier grass to come close to the 60% threshold for cellulosic biofuel. Therefore, EPA is including cellulosic biofuel produced from the cellulose, hemicelluloses and lignin portions of energy cane, giant reed, and napiergrass under the same pathways for which cellulosic biomass from switchgrass qualifies under the RFS2 final rule.

C. Lifecycle Greenhouse Gas Emissions Analysis for Certain Renewable Gasoline and Renewable Gasoline Blendstocks Pathways

In this rule, EPA is also adding pathways to Table 1 to § 80.1426 for the production of renewable gasoline and renewable gasoline blendstock using specified feedstocks, fuel production processes, and process energy sources. The feedstocks we considered are generally considered waste feedstocks such as crop residues or cellulosic components of separated yard waste. These feedstocks have been identified by the industry as the most likely feedstocks for use in making renewable gasoline or renewable gasoline blendstock in the near term due to their availability and low cost. Additionally, these feedstocks have already been analyzed by EPA as part of the RFS2 rulemaking for the production of other fuel types. Consequently, no new modeling is required and we rely on earlier assessments of feedstock production and distribution for assessing the likely lifecycle impact on renewable gasoline and renewable gasoline blendstock. We have also relied on the petroleum gasoline baseline assessment from the RFS2 rule for estimating the fuel distribution and use GHG emissions impacts for renewable gasoline and renewable gasoline blendstock. Consequently, the only new analysis required is of the technologies for turning the feedstock into renewable

[46] The F–T diesel process modeled applies to cellulosic diesel, jet fuel, heating oil, and naphtha.

gasoline and renewable gasoline blendstock.

1. Feedstock Production and Distribution

EPA has evaluated renewable gasoline and renewable gasoline blendstock pathways that utilize cellulosic feedstocks currently included in Table 1 to § 80.1426 of the regulations. The following feedstocks were evaluated:

- Cellulosic biomass from crop residue, slash, pre-commercial thinnings and tree residue, annual cover crops;
- Cellulosic components of separated yard waste;
- Cellulosic components of separated food waste; and
- Cellulosic components of separated MSW.

The FASOM and FAPRI models were used to analyze the GHG impacts of the feedstock production portion of a fuel's lifecycle. In the RFS2 rulemaking, FASOM and FAPRI modeling was performed to analyze the emissions impact of using corn stover as a biofuel feedstock and this modeling was extended to some additional feedstock sources considered similar to corn stover. This approach was used for crop residues, slash, pre-commercial thinnings, tree residue and cellulosic components of separated yard, food, and MSW. These feedstocks are all excess materials and thus, like corn stover, were determined to have little or no land use change GHG impacts. Their GHG emission impacts are mainly associated with collection, transport, and processing into biofuel. See the RFS2 rulemaking preamble for further discussion. We used the results of the corn stover modeling in this analysis to estimate the upper bound of agricultural sector impacts from the production of the various cellulosic feedstocks noted above.

The agriculture sector modeling results for corn stover represent all of the direct and significant indirect emissions in the agriculture sector (feedstock production emissions) for a certain quantity of corn stover produced. For the RFS2 rulemaking, this was roughly 62 million dry tons of corn stover to produce 5.7 billion gallons of ethanol assuming biochemical fermentation to ethanol processing. We have calculated GHG emissions from feedstock production for that amount of corn stover. The GHG emissions were then divided by the total heating value of the fuel to get feedstock production emissions per mmBtu of fuel. In addition to the biochemical ethanol process, a similar analysis was completed for thermochemical ethanol and F–T diesel pathways as part of the RFS2 rulemaking.

In this rulemaking we are analyzing renewable gasoline and renewable gasoline blendstock produced from corn stover (and, by extension, other waste feedstocks). The number of gallons of fuel produced from a ton of corn stover (modeled process yields) is specific to the process used to produce renewable fuel. EPA has adjusted the results of the earlier corn stover modeling to reflect the different process yields and heating value of renewable gasoline or renewable gasoline blendstock product. The results of this calculation are shown below in Table 7.

We based our process yields and heating values for renewable gasoline and renewable gasoline blendstock on several process technologies representative of technologies anticipated to be used in producing these fuels. As discussed later in this section, there are four main types of fuel production technologies available for producing renewable gasoline. These four processes can be characterized as (1) thermochemical gasification, (2) catalytic pyrolysis and upgrading to renewable gasoline or renewable gaoline blendstock (''catalytic pyrolysis''), (3) biochemical fermentation with upgrading to renewable gasoline or renewable gasoline blendstock via carboxylic acid (''fermentation and upgrading''), and (4) direct biochemical fermentation to renewable gasoline and renewable gasoline blendstock (''direct fermentation''). The thermochemical gasification process was modeled as part of the RFS2 final rule, included as producing naptha via the F–T process. Our analysis of the catalytic pyrolysis process was based on the modeling work completed by the National Renewable Energy Laboratory (NREL) for this rule for a process to make renewable gasoline blendstock.[47] The fermentation and upgrading process was modeled based on confidential business information (CBI) from industry for a unique process which uses biochemical conversion of cellulose to renewable gasoline via a carboxylic acid route. In addition, we have qualitatively assessed the direct fermentation to renewable gasoline process based on similarities to the biochemical ethanol process already analyzed as part of the RFS2 rulemaking. The fuel production section below provides further discussion on extending the GHG emissions results of the biochemical ethanol fermentation process to a biochemical renewable gasoline or renewable gasoline blendstock fermentation process. In some cases, the available data sources included process yields for renewable gasoline or renewable gasoline blendstock produced from wood chips rather than corn stover which was specifically modeled as a feedstock in the RFS2 final rule. We believe that the process yields are not significantly impacted by the source of cellulosic material whether the cellulosic material comes from residue such as corn stover or wood material such as from tree residues. We made the simplifying assumption that one dry ton of wood feedstock produces the same volume of renewable gasoline or renewable gasoline blendstock as one dry ton of corn stover. We believe this is reasonable considering that the RFS2 rulemaking analyses for biochemical ethanol and thermochemical F–T diesel processes showed limited variation in process yields between different feedstocks for a given process technology.[48] In addition, since the renewable gasoline and renewable gasoline blendstock pathways include feedstocks that were already considered as part of the RFS2 final rule, the existing feedstock lifecycle GHG impacts for distribution of corn stover were also applied to this analysis.[49]

Feedstock production emissions are shown in Table 7 below for corn stover. Corn stover feedstock production emissions are mainly a result of corn stover removal increasing the profitability of corn production (resulting in shifts in cropland and thus slight emission impacts) and also the need for additional fertilizer inputs to replace the nutrients lost when corn stover is removed. However, corn stover removal also has an emissions benefit as it encourages the use of no-till farming which results in the lowering of domestic land use change emissions. This change to no-till farming results in a negative value for domestic land use change emission impacts (see also Table 13 below). For other waste feedstocks (*e.g.,* tree residues and cellulosic components of separate yard, food, and MSW), the feedstock production emissions are even lower than the values shown for corn stover since the use of such feedstocks does not require land use changes or additional agricultural inputs. Therefore, we conclude that if the use of corn stover

[47] Kinchin, Christopher. Catalytic Fast Pyrolysis with Upgrading to Gasoline and Diesel Blendstocks. National Renewable Energy Laboratory (NREL). 2011.

[48] Aden, Andy. Feedstock Considerations and Impacts on Biorefining. National Renewable Energy Laboratory (NREL). December 2009.

[49] Results for feedstock distribution are aggregated along with fuel distribution and are reported in a later section, see conclusion section.

as a feedstock in the production of renewable gasoline and renewable gasoline blendstock yields lifecycle GHG emissions results for the resulting fuel that qualify it as cellulosic biofuel (*i.e.,* it has at least a 60% lifecycle GHG reduction as compared to conventional fuel), then the use of other waste feedstocks with little or no land use change emissions will also result in renewable gasoline or renewable gasoline blendstock that qualifies as cellulosic biofuel.

TABLE 7—FEEDSTOCK PRODUCTION EMISSIONS FOR RENEWABLE GASOLINE AND RENEWABLE GASOLINE BLENDSTOCK PATHWAYS USING CORN STOVER

Feedstock production emission sources	Catalytic pyrolysis to renewable gasoline blendstock (g CO_2-eq./mmBtu)	Biochemical fermentation to renewable gasoline via carboxylic acid (g CO_2-eq./mmBtu)	Direct biochemical fermentation process to renewable gasoline and renewable gasoline blendstock (g CO_2-eq./mmBtu)
Domestic Livestock	7,648	6,770	~ 9,086
Domestic Farm Inputs and Fertilizer N_2O	1,397	1,237	~ 1,660
Domestic Rice Methane	366	324	~ 434
Domestic Land Use Change	−9,124	−8,076	~ −10,820
International Livestock	0	0	0
International Farm Inputs and Fertilizer N_2O	0	0	0
International Rice Methane	0	0	0
International Land Use Change	0	0	0
Total Feedstock Production Emissions	287	254	~ 361

The results in Table 7 differ for the different pathways considered because of the different amounts of corn stover used to produce the same amount of fuel in each case. Table 7 only considers the feedstock production impacts associated with the renewable gasoline pathways, other aspects of the lifecycle are discussed in the following sections.

2. Fuel Distribution

A petroleum gasoline baseline was developed as part of the RFS2 final rule which included estimates for fuel distribution emissions. Since renewable gasoline and renewable gasoline blendstocks when blended into gasoline are similar to petroleum gasoline, it is reasonable to assume similar fuel distribution emissions. Therefore, the existing fuel distribution lifecycle GHG impacts of the petroleum gasoline baseline from the RFS2 final rule were applied to this analysis.

3. Use of the Fuel

A petroleum gasoline baseline was developed as part of the RFS2 final rule which estimated the tailpipe emissions from fuel combustion. Since renewable gasoline and renewable gasoline blendstock are similar to petroleum gasoline, the non-CO_2 combustion emissions calculated as part of the RFS2 final rule for petroleum gasoline were applied to our analysis of the renewable gasoline and renewable gasoline blendstock pathways. Only non-CO_2 emissions were included since carbon fluxes from land use change are accounted for as part of the biomass feedstock production.

4. Fuel Production

In the RFS2 rulemaking, EPA analyzed several of the main cellulosic biofuel pathways: a biochemical fermentation process to ethanol and two thermochemical gasification processes, one producing mixed alcohols (primarily ethanol) and the other one producing mixed hydrocarbons (primarily diesel fuel). These pathways all exceeded the 60% lifecycle GHG threshold requirements for cellulosic biofuel using the specified feedstocks. Refer to the preamble and regulatory impact analysis (RIA) from the final RFS2 rule for more details. From these analyses, it was determined that ethanol and diesel fuel produced from the specified cellulosic feedstocks and processes would be eligible for cellulosic and advanced biofuel RINs.

The thermochemical gasification process to diesel fuel (via F–T synthesis) also produces a smaller portion of naphtha, a gasoline blendstock. In the final RFS2 rule, naphtha produced with specified cellulosic feedstocks by a F–T process was included as exceeding the 60% lifecycle GHG threshold, with an applicable D–Code of 3, in Table 1 to § 80.1426.

Since the final RFS2 rule was released, EPA has received several petitions and inquiries that suggest that renewable gasoline or renewable gasoline blendstock produced using processes other than the F–T process could also qualify for a similar D–Code of 3.[50] For the reasons described below, we have decided to authorize the generation of RINs with a D code of 3 for renewable gasoline and renewable gasoline blendstock produced using specified cellulosic feedstocks for the processes considered here.

Several routes have been identified as available for the production of renewable gasoline and renewable gasoline blendstock from renewable biomass. These include catalytic pyrolysis and upgrading to renewable gasoline or renewable gasoline blendstock (''catalytic pyrolysis''), biochemical fermentation with upgrading to renewable gasoline or renewable gasoline blendstock via carboxylic acid (''fermentation and upgrading''), and direct biochemical fermentation to renewable gasoline and renewable gasoline blendstock (''direct fermentation'').[51] [52]

Similar to how we analyzed several of the main routes for cellulosic ethanol and cellulosic diesel for the final RFS2 rule, we have chosen to analyze the main renewable gasoline and renewable gasoline blendstock pathways in order to estimate the potential GHG reduction profile for renewable gasoline and renewable gasoline blendstock across a

[50] See *http://www.epa.gov/otaq/fuels/renewablefuels/compliancehelp/rfs2-lca-pathways.htm* for list of petitions received by EPA.

[51] Regalbuto, John. ''An NSF perspective on next generation hydrocarbon biorefineries,'' Computers and Chemical Engineering 34 (2010) 1393–1396. February 2010.

[52] Serrano-Ruiz, J., Dumesic, James. ''Catalytic routes for the conversion of biomass into liquid hydrocarbon transportation fuels,'' Energy Environmental Science (2011) 4, 83–99.

range of other production technologies for which we are confident will have at least as great of GHG emission reductions as those specifically analyzed.

a. Catalytic Pyrolysis to Renewable Gasoline and Renewable Gasoline Blendstock

The first production process we investigated for this rule is a catalytic fast pyrolysis route to bio-oils with upgrading to a renewable gasoline or a renewable gasoline blendstock. We utilized process modeling results from the National Renewable Energy Laboratory (NREL). Information provided by industry and claimed as CBI are based on similar processing methods and suggest similar results than those reported by NREL. Details on the NREL modeling are described further in a technical report available through the docket.[53] Catalytic pyrolysis involves the rapid heating of biomass to about 500°C at slightly above atmospheric pressure. The rapid heating thermally decomposes biomass, converting it into pyrolysis vapor, which is condensed into a liquid bio-oil. The liquid bio-oil can then be upgraded using conventional hydroprocessing technology and further separated into gasoline and diesel blendstock streams (cellulosic diesel from catalytic pyrolysis is already included as an acceptable pathway in the RFS2 program). Some industry sources also expect to produce smaller fractions of heating oil in addition to gasoline and diesel blendstocks. Excess electricity from the process is also accounted for in our modeling as a co-product credit in which any excess displaces U.S. average grid electricity. Excess electricity is generated from the use of co-product coke/char and product gases and is available because internal electricity demands are fully met. The estimated energy inputs and electricity credits shown in Table 8, below, utilize the data provided by the NREL process modeling. However, Industry sources also identified potential areas for improvements in energy use, such as the use of biomass fired dryers instead of natural gas fired dryers for drying incoming wet feedstocks and increased turbine efficiencies for electricity production which may result in lower energy consumption than estimated by NREL and thus improve GHG performance compared to our estimates here.

TABLE 8—2022 ENERGY USE AT CELLULOSIC BIOFUEL FACILITIES

[Btu/gal]

Technology	Biomass use	Natural gas use	Purchased electricity	Sold electricity
Catalytic Pyrolysis to Renewable Gasoline Blendstock	136,000	51,000	0	−2,000

The emissions from energy inputs were calculated by multiplying the amount of energy by emission factors for fuel production and combustion, based on the same method and factors used in the RFS2 final rulemaking. The emission factors for the different fuel types are from GREET and were based on assumed carbon contents of the different process fuels. The emissions from producing electricity in the U.S. were also taken from GREET and represent average U.S. grid electricity production emissions.

The major factors influencing the emissions from the fuel production stage of the catalytic pyrolysis pathway are the use of natural gas (mainly due to hydrogen production for hydroprocessing) and the co-products available for additional heat and power generation.[54] See Table 9 for a summary of emissions from fuel production.

TABLE 9—FUEL PRODUCTION EMISSIONS FOR CATALYTIC PYROLYSIS TO RENEWABLE GASOLINE BLENDSTOCK USING CORN STOVER

Lifecycle stage	Catalytic pyrolysis to renewable gasoline blendstock (g CO_2-eq./mmBtu)
On-Site & Upstream Emissions (Natural Gas & Biomass*)	31,000
Electricity Co-Product Credit	−3,000
Total Fuel Production Emissions:	28,000

Only non-CO_2 combustion emissions from biomass.

b. Fermentation and Upgrading to Renewable Gasoline and Renewable Gasoline Blendstock

The second production process we investigated is a biochemical fermentation process to intermediate carboxylic acids with catalytic upgrading to renewable gasoline or renewable gasoline blendstock. This process involves the fermentation of biomass using a mixed-culture of microorganisms that produce a variety of carboxylic acids. If the feedstock has high lignin content, then the biomass is pretreated to enhance digestibility. The acids are then neutralized to carboxylate salts and further converted to ketones and alcohols for refining into gasoline, diesel, and jet fuel.

The process requires the use of natural gas and hydrogen inputs.[55] No purchased electricity is required as lignin is projected to be used to meet all facility demands as well as provide excess electricity to the grid. EPA used the estimated energy and material inputs along with emission factors to estimate the GHG emissions from this process. The energy inputs and electricity credits are shown in Table 10, below. These inputs are based on Confidential Business Information (CBI), rounded to the nearest 1000 units, provided by industry as part of the petition process for new fuel pathways.

[53] Kinchin, Christopher. Catalytic Fast Pyrolysis with Upgrading to Gasoline and Diesel Blendstocks. National Renewable Energy Laboratory (NREL). 2011.

[54] A steam methane reformer (SMR) is used to produce the hydrogen necessary for hydroprocessing. In the U.S. over 95% of hydrogen is currently produced via steam reforming (DOE, 2002 ''A National Vision of America's Transition to a Hydrogen Economy to 2030 and Beyond''). Other alternatives are available, such as renewable or nuclear resources used to extract hydrogen from water or the use of biomass to produces hydrogen. These alternative methods, however, are currently not as efficient or cost effective as the use of fossil fuels and therefore we conservatively estimate emissions from hydrogen production using the more commonly used SMR technology.

[55] Hydrogen emissions are modeled as natural gas and electricity demands.

TABLE 10—2022 ENERGY USE AT CELLULOSIC FACILITY

[Btu/gal]

Technology	Biomass use	Natural gas use	Purchased electricity	Sold electricity
Biochemical Fermentation to Renewable Gasoline or Renewable Gasoline Blendstock via Carboxylic Acid	49,000	59,000	0	−2,000

The process also uses a small amount of buffer material as neutralizer which was not included in the GHG lifecycle results due to its likely negligible emissions impact. The GHG emissions estimates from the fuel production stage are seen in Table 11.

TABLE 11—FUEL PRODUCTION EMISSIONS FOR BIOCHEMICAL FERMENTATION TO RENEWABLE GASOLINE OR RENEWABLE GASOLINE BLENDSTOCK VIA CARBOXYLIC ACID USING CORN STOVER

Lifecycle stage	GHG Emissions (g CO_2-eq./mmBtu)
On-Site & Upstream Emissions (Natural Gas & Biomass*)	33,000
Electricity Co-Product Credit	−3,000
Total Fuel Production Emissions:	30,000

*Only non-CO_2 combustion emissions from biomass

c. Direct Fermentation to Renewable Gasoline and Renewable Gasoline Blendstock

The third production process we investigated involves the use of microorganisms to ferment sugars hydrolyzed from cellulose directly into hydrocarbons which could be either a complete fuel as renewable gasoline or a renewable gasoline blendstock. The process is similar to the biochemical fermentation to ethanol pathway modeled for the final RFS2 rule with the major difference being the end fuel product, hydrocarbons instead of ethanol. Researchers believe that this new technology could achieve improvements over classical fermentation approaches because hydrocarbons separate spontaneously from the aqueous phase, thereby avoiding poisoning of microbes by the accumulated products and facilitating separation/collection of alkanes from the reaction medium.[56] In other words, some energy savings may result because fewer separation unit operations could be required for separating the final product from other reactants and there may be better conversion yields as the fermentation microorganisms are not poisoned when interacting with accumulated products. We also expect that the lignin/byproduct portions of the biomass from the fermentation to hydrocarbon process could be converted into heat and electricity for internal demands or for export, similar to the biochemical fermentation to ethanol pathway.

Therefore, we can conservatively extend our final RFS2 rule biochemical fermentation to ethanol process results to a similar (but likely slightly improved) process that instead produces hydrocarbons. Since the final RFS2 rule cellulosic ethanol GHG results were well above the 60% GHG reduction threshold for cellulosic biofuels, if actual emissions from other necessary changes to the direct biochemical fermentation to hydrocarbons process represent some small increment in GHG emissions, the pathway would still likely meet the threshold. Table 12 is our qualitative assessment of the potential emissions reductions from a process using biochemical fermentation to cellulosic hydrocarbons assuming similarities to the biochemical fermentation to cellulosic ethanol route from the final RFS2 rule.

TABLE 12—FUEL PRODUCTION EMISSIONS FOR RFS2 CELLULOSIC BIOCHEMICAL ETHANOL COMPARED TO DIRECT BIOCHEMICAL FERMENTATION TO RENEWABLE GASOLINE OR RENEWABLE GASOLINE BLENDSTOCK USING CORN STOVER

Lifecycle stage	RFS2 Cellulosic biochemical ethanol emissions (g CO_2-eq./mmBtu)	Direct biochemical fermentation to renewable gasoline and renewable gasoline blendstock emissions (g CO_2-eq./mmBtu)
On-Site Emissions & Upstream (biomass)	3,000	< or = 3,000
Electricity Co-Product Credit	−35,000	= −35,000
Total Fuel Production Emissions[57]	−33,000	< or = −33,000

Table 13 below breaks down by stage the lifecycle GHG emissions for the renewable gasoline and renewable gasoline blendstock pathways using corn stover and the 2005 petroleum baseline. The table demonstrates the contribution of each stage in the fuel pathway and its relative significance in terms of GHG emissions. These results are also presented in graphical form in a supplemental memorandum to the docket.[58] As noted above, these analyses assume natural gas as the process energy when needed; using biogas or biomass as process energy would result in an even better lifecycle GHG impact.

[56] Serrano-Ruiz, J., Dumesic, James. ''Catalytic routes for the conversion of biomass into liquid hydrocarbon transportation fuels,'' Energy Environmental Science (2011) 4, 83–99.

[57] Numbers do not add up due to rounding.

[58] Memorandum to the Air and Radiation Docket EPA–HQ–OAR–2011–0542 ''Supplemental Information for Renewable Gasoline and Renewable Gasoline Blendstock Pathways Under the Renewable Fuel Standard (RFS2) Program''.

TABLE 13—LIFECYCLE GHG EMISSIONS FOR RENEWABLE GASOLINE AND RENEWABLE GASOLINE BLENDSTOCK PATHWAYS USING CORN STOVER, 2022

[kg CO_2-eq./mmBtu]

Fuel type	Catalytic pyrolysis to renewable gasoline blendstock	Biochemical fermentation to renewable gasoline via carboxylic acid	Direct biochemical fermentation to renewable gasoline and renewable gasoline blendstock	2005 gasoline baseline
Net Domestic Agriculture (w/o land use change)	9	8	~ 11	
Net International Agriculture (w/o land use change):				
Domestic Land Use Change	−9	−8	~ −11	
International Land Use Change:				
Fuel Production	28	30	< or = −33	19
Fuel and Feedstock Transport	2	2	~ 2	*
Tailpipe Emissions	2	2	~ 1	79
Total Emissions	32	34	< or = −29	98
% Change from Baseline	−67%	−65%	−129%	

* Emissions included in fuel production stage.

d. Extension of Modeling Results to Other Production Processes Producing Renewable Gasoline or Renewable Gasoline Blendstock

In the RFS2 rulemaking, we modeled the GHG emissions results from the biochemical fermentation process to ethanol, thermochemical gasification processes to mixed alcohols (primarily ethanol) and mixed hydrocarbons (primarily diesel fuel). We extended these modeled process results to apply when the biofuel was produced from ''any'' process. We determined that since we modeled multiple cellulosic biofuel processes and all were shown to exceed the 60% lifecycle GHG threshold requirements for cellulosic biofuel using the specified feedstocks its was reasonable to extend to other processes that might develop as these would likely represent improvements over existing processes as the industry works to improve the economics of cellulosic biofuel production by, for example, reducing energy consumption and improving process yields. Similarly, this rule assesses multiple processes for the production of renewable gasoline and renewable gasoline blendstocks and all were shown to exceed the 60% lifecycle GHG threshold requirements for cellulosic biofuel using specified feedstocks.

As was the case in our earlier rulemaking, a couple reasons in particular support extending our modeling results to other production process producing renewable gasoline or renewable gasoline blendstock from cellulosic feedstock. Under this rule we analyzed the core technologies most likely available through 2022 for production of renewable gasoline and renewable gasoline blendstock routes from cellulosic feedstock as shown in literature. [59] [60] The two primary routes for renewable gasoline and renewable gasoline blendstock production from cellulosic feedstock can be classified as either thermochemical or biological. Each of these two major categories has two subcategories. The processes under the thermochemical category include:

- Pyrolysis—in which cellulosic biomass is decomposed with temperature to bio-oils and requires further catalytic processing to produce a finished fuel.
- Gasification—in which cellulosic biomass is decomposed to syngas with further catalytic processing of methanol to gasoline or through Fischer-Tropsch (F–T) synthesis to gasoline.

The processes under the biochemical category include:

- Direct fermentation—requires the release of sugars from biomass and the use of ''synthetic biology'' in which microorganisms are altered to ferment sugars straight into hydrocarbons instead of alcohols.
- Fermentation w/catalytic upgrading—requires the release of sugars from biomass and aqueous- or liquid-phase processing of sugars or intermediate fermentation products into hydrocarbons using solid catalysts,

As part of the modeling effort here, as well as for the RFS2 final rule, we have considered the lifecycle GHG impacts of the four possible production technologies mentioned above. The pyrolysis, direct fermentation, and fermentation with catalytic upgrading are considered in this rule and the gasification route was already included in the RFS2 final rule. In all cases, the processes that we have considered meet the 60% lifecycle GHG reduction required for cellulosic biofuels. Furthermore, we believe that the results from our modeling would cover all the likely variations within these potential routes for producing renewable gasoline and renewable gasoline blendstock which also use natural gas, biogas or biomass for process energy and that all such production variations would also meet the 60% lifecycle threshold.

The main reason for this is that we believe that our energy input assumptions are reasonable at this time but probably in some cases conservative for commercial scale cellulosic facilities. The cellulosic industry is in its early stages of development and many of the estimates of process technology GHG impacts is based on pre-commercial scale assessments and demonstration programs. Commercial scale cellulosic facilities will continue to make efficiency improvements over time to maximize their fuel products/co-products and minimize wastes. For cellulosic facilities, such improvements include increasing conversion yields and fully utilizing the biomass input for valuable products.

An example of increasing the amount of biomass utilized is the combustion of undigested or unconverted biomass for heat and power. The three routes that we analyzed for the production of renewable gasoline and renewable gasoline blendstock in today's rule assume an electricity production credit from the economically-driven use of

[59] Regalbuto, John. ''An NSF perspective on next generation hydrocarbon biorefineries,'' Computers and Chemical Engineering 34 (2010) 1393–1396. February 2010.

[60] Serrano-Ruiz, J., Dumesic, James. ''Catalytic routes for the conversion of biomass into liquid hydrocarbon transportation fuels,'' Energy Environmental Science (2011) 4, 83–99.

lignin or waste byproducts; we also ran a sensitivity case where no electricity credit was given. We found that all of the routes analyzed would still pass the GHG threshold without an electricity credit, providing confidence that over the range of technology options, these process technologies will surely allow the cellulosic biofuel produced to exceed the threshold for cellulosic biouel GHG performance. Without excess electricity production the catalytic pyrolysis pathway results in a 65% lifecycle GHG reduction, the biochemical fermentation via carboxylic acid pathway results in a 62% lifecycle GHG reduction, and the direct biochemical fermentation pathway results in a 93% reduction in lifecycle GHG emissions compared to the petroleum fuel baseline.

Additionally, while the final results reported in this rule include an electricity credit, this electricity credit is based on current technology for generating electricity; it is possible that over the next decade as cellulosic biofuel production matures, the efficiency with which electricity is generated at these facilities will also improve. Such efficiency improvements will tend to improve the GHG performance for cellulosic biofuel technologies in general including those used to produce renewable gasoline.

Furthermore, industry has identified other areas for energy improvements which our current pathway analyses do not include. Therefore, the results we have come up with for the individual pathway types represent conservative estimates and any variations in the pathways considered are likely to result in greater GHG reductions that what is considered here. For example, the variation of the catalytic pyrolysis route considered here resulted in a 67% reduction in lifecycle GHG emissions compared to the petroleum baseline. However, as was mentioned this was based on data from our NREL modeling and industry CBI data indicated more efficient energy performance which, if realized, would improve GHG performance. Another area for improvement in this pathway could be the use of anaerobic digestion to treat organics in waste water. If the anaerobic digestion is on-site, then enough biogas could potentially be produced to replace all of the fossil natural gas used as fuel and about half the natural gas fed for hydrogen production.[61] Thus, fossil natural gas consumption could be further minimized under certain scenarios. We believe that as commercial scale cellulosic facilities develop, more of these improvements will be made to maximize the use of all the biomass and waste byproducts available to bring the facility closer to energy self-sufficiency. These improvements could help to increase the economic profitability for cellulosic facilities where fossil energy inputs become costly to purchase. Therefore we can extend the modeling results for our pyrolysis route to all variations of this production technology which use natural gas, biogas or biomass for production energy for producing renewable gasoline or renewable gasoline blendstock.

The F–T gasification technology route considered as part of the RFS2 final rule resulted in an approximately 91% reduction in lifecycle GHG emissions compared to the petroleum baseline. This could be considered a conservative estimate as the process did not assume any excess electricity production, which as mentioned above could lead to additional GHG reductions. The F–T process involves gasifying biomass into syngas (mix of H_2 and CO) and then converting the syngas through a catalytic process into a hydrocarbon mix that is further refined into finished product. The F–T process considered was based on producing both gasoline and diesel fuel so that it was not optimized for renewable gasoline production. A process for producing primarily renewable gasoline rather than diesel from a gasification route should not result in a significantly worse GHG impacts compared to the mixed fuel process analyzed. Furthermore, as the lifecycle GHG reduction from the F–T process considered was around 91%, there is considerable room for variations in this route to still meet the 60% lifecycle GHG reduction threshold for cellulosic fuels. Therefore, in addition to the F–T process orginially analyzed for producing naphtha, we can extend the results based on the above analyses to include all variations of the gasification route which use natural gas, biogas or biomass for production energy for producing renewable gasoline or renewable gasoline blendstock. These variations include for example different catalysts and different refining processes to produce different mixes of final fuel product. While the current Table 1 entry in the regulations does not specify process energy sources, we are adding these specific eligible energy sources since we have not analyzed other energy sources (*e.g.* coal) as also allowing the pathway to meet the GHG performance threshold.

There is an even wider gap between the results modeled for the direct fermentation route and the cellulosic lifecycle GHG threshold. The variation we considered for the direct fermentation process resulted in an approximately 129% reduction in lifecycle GHG emissions compared to the petroleum baseline. This process did consider production of electricity as part of the process but as mentioned even if this was not the case the pathway would still easily fall below the 60% lifecycle threshold for cellulosic biofuels. If actual emissions from other necessary changes to the direct biochemical fermentation to hydrocarbons process represent some small increment in GHG emissions, the pathway would still likely meet the threshold. Therefore, we can extend the results to all variations of the direct biochemical route for renewable gasoline or renewable gasoline blendstock production which use natural gas, biogas or biomass for production energy.

The biochemical with catalytic upgrading route that we evaluated resulted in a 65% reduction in GHG emissions compared to the petroleum baseline. However, this can be considered a conservative estimate. For instance, the biochemical fermentation to gasoline via carboxylic acid route considered did not include the potential for generating steam from the combustion of undigested biomass and then using this steam for process energy. If this had been included, natural gas consumption could potentially be decreased which would lower the potential GHG emissions estimated from the process. Therefore, the scenario analyzed could be considered conservative in estimating actual natural gas usage. As was the case with the pyrolysis route considered, we believe that as commercial scale cellulosic facilities develop, improvements will be made to maximize the use of all the biomass and waste byproducts available to bring the facility closer to energy self-sufficiency. These improvements help to increase the economic profitability for cellulosic facilities where fossil energy inputs become costly to purchase. The processes we analyzed for this rulemaking utilized a mix of natural gas and biomass for process energy, with biogas replacing natural gas providing improved GHG performance. We have not analyzed other fuel types (*e.g.*, coal) and are therefore not approving processes that utilized other fuel sources at this point. Therefore, we are extending our results

[61] Kinchin, Christopher. Catalytic Fast Pyrolysis with Upgrading to Gasoline and Diesel Blendstocks. National Renewable Energy Laboratory (NREL). 2011.

to include all variations of the biochemical with catalytic upgrading process utilizing natural gas, biogas or biomass for process energy.

While actual cellulosic facilities may show some modifications to the process scenarios we have already analyzed, our results give a good indication of the range of emissions we could expect from processes producing renewable gasoline and renewable gasoline blendstock from cellulosic feedstock, all of which meet the 60% cellulosic biofuel threshold (assuming they are utilizing natural gas, biogas or biomass for process energy). Technology changes in the future are likely to increase efficiency to maximize profits, while also lowering lifecycle GHG emissions. Therefore, we have concluded that since all of the renewable gasoline or renewable gasoline blendstock fuel processing methods we have analyzed exceed the 60% threshold using specific cellulosic feedstock types, we can conclude that processes producing renewable gasoline or renewable gasoline blendstock that fit within the categories of process analyzed here and are produced from the same feedstock types and using natural gas, biogas or biomass for process energy use will also meet the 60% GHG reduction threshold. In addition, while other technologies may develop, we expect that they will only become commercially competitive if they have better yield (more gallons per ton of feedstock) or lower production cost due to lower energy consumption. Both of these factors would suggest better GHG performance. This would certainly be the case if such processes also relied upon using biogas and/or biomass as the primary energy source. Therefore based on our review of the existing primary cellulosic biofuel production processes, likely GHG emission improvements for existing or new technologies, and consideration of the positive GHG emissions benefits associated with using biogas and/or biomass for process energy, we are approving for cellulosic RIN generation any process for renewable gasoline and renewable gasoline blendstock production using specified cellulosic biomass feedstocks as long as the process utilizes biogas and/or biomass for all process energy.

5. Summary

Three renewable gasoline and renewable gasoline blendstock pathways were compared to baseline petroleum gasoline, using the same value for baseline gasoline as in the RFS2 final rule analysis. The results of the analysis indicate that the renewable gasoline and renewable gasoline blendstock pathways result in a GHG emissions reduction of 65–129% or better compared to the gasoline fuel it would replace using corn stover as a feedstock. Since the renewable gasoline and renewable gasoline blendstock pathways which use corn stover as a feedstock all exceed the 60% lifecycle GHG threshold requirements for cellulosic biofuel, and since these pathways capture the likely current technologies and since future technology improvements are likely to increase efficiency and lower GHG emissions, we have determined that all processes producing renewable gasoline or renewable gasoline blendstock from corn stover can qualify if they fall in the following process characterizations:

- Catalytic pyrolysis and upgrading utilizing natural gas, biogas, and/or biomass as the only process energy sources.
- Gasification and upgrading utilizing natural gas, biogas, and/or biomass as the only process energy sources.
- Direct fermentation utilizing natural gas, biogas, and/or biomass as the only process energy sources.
- Fermentation and upgrading utilizing natural gas, biogas, and/or biomass as the only process energy sources.
- Any process utilizing biogas and/or biomass as the only process energy sources.

As was the case for extending corn stover results to other feedstocks in the RFS2 final rule, these results are also reasonably extended to feedstocks with similar or lower GHG emissions profiles, including the following feedstocks:

- Cellulosic biomass from crop residue, slash, pre-commercial thinnings and tree residue, annual cover crops;
- Cellulosic components of separated yard waste;
- Cellulosic components of separated food waste; and
- Cellulosic components of separated MSW.

For more information on the reasoning for extension to these other feedstocks refer to the feedstock production and distribution section or the RFS2 rulemaking (75 FR 14793–14795).

Based on these results, today's rule includes pathways for the generation of cellulosic biofuel RINs for renewable gasoline or renewable gasoline blendstock produced by catalytic pyrolysis and upgrading, gasification and upgrading, direct fermentation, fermentation and upgrading, all utilizing natural gas, biogas, and/or biomass as the only process energy sources or any process utilizing biogas and/or biomass as the only energy sources, and using corn stover as a feedstock or the feedstocks noted above. In order to qualify for RIN generation, the fuel must meet the other definitional criteria for renewable fuel (*e.g.*, produced from renewable biomass, and used to reduce or replace petroleum-based transportation fuel, heating oil or jet fuel) specified in the Clean Air Act and the RFS regulations.

A manufacturer of a renewable motor vehicle gasoline (including parties using a renewable blendstock obtained from another party), must satisfy EPA motor vehicle registration requirements in 40 CFR Part 79 for the fuel to be used as a transportation fuel. Per 40 CFR 79.56(e)(3)(i), a renewable motor vehicle gasoline would be in the Non-Baseline Gasoline category or the Atypical Gasoline category (depending on its properties) since it is not derived only from conventional petroleum, heavy oil deposits, coal, tar sands and/or oil sands (40 CFR 79.56(e)(3)(i)(5)).In either case, the Tier 1 requirements at 40 CFR 79.52 (emissions characterization) and the Tier 2 requirements at 40 CFR 79.53 (animal exposure) are conditions for registration unless the manufacturer qualifies for a small business provision at 40 CFR 79.58(d). For a non-baseline gasoline, a manufacturer under $50 million in annual revenue is exempt from Tier 1 and Tier 2. For an atypical gasoline there is no exemption from Tier 1, but a manufacturer under $10 million in annual revenue is exempt from Tier 2.

Registration for a motor vehicle gasoline at 40 CFR 79 is via EPA Form 3520–12, Fuel Manufacturer Notification for Motor Vehicle Fuel, available at: *http://www.epa.gov/otaq/regs/fuels/ffarsfrms.htm.*

D. Esterification Production Process Inclusion for Specified Feedstocks Producing Biodiesel

Table 14, shown below, includes pathways for biodiesel using specified feedstocks and the production process transesterification. Transesterification is the most commonly used method to produce biodiesel (*i.e.,* methyl esters) by

[62] Commonly used base catalysts include sodium hydroxide (NaOH), potassium hydroxide (KOH) and sodium methoxide ($NaOCH_3$).

reacting triglycerides with methanol typically under the presence of a base catalyst, see the simplified form in Equation 1.[62]

TABLE 14—EXCERPTS OF EXISTING FUEL PATHWAYS FROM § 40 CFR 80.1426

Fuel type	Feedstock	Production process requirements	D-Code
Biodiesel, and renewable diesel	Soy bean oil; Oil from annual covercrops; Algal oil; Biogenic waste oils/fats/greases; Non-food grade corn oil.	One of the following: Trans-Esterification Hydrotreating Excluding processes that co-process renewable biomass and petroleum.	4 (Biomass-Based Diesel).
Biodiesel, and renewable diesel	Soy bean oil; Oil from annual covercrops; Algal oil; Biogenic waste oils/fats/greases; Non-food grade corn oil.	One of the following: Trans-Esterification Hydrotreating Includes only processes that co-process renewable biomass and petroleum.	5 (Advanced Biofuel).

Equation 1: Transesterification

$$\text{Triglyceride (Ester)} + \text{Methanol (Alcohol)} \xrightarrow[\text{(catalyst)}]{} \text{Methyl Ester (Ester)} + \text{Glycerin}$$

While triglycerides are usually the main component of oils, fats, and grease feedstocks, there are other components such as free fatty acids (FFAs) that are typically removed prior to transesterification. Removal or conversion of FFAs is important if the traditional base-catalyzed transesterification production process is used since FFAs will react with base catalysts to produce soaps that inhibit the transesterification reaction. Table 15 below gives the usual ranges for FFAs found in biodiesel feedstocks.

TABLE 15—RANGES OF FFA IN BIODIESEL FEEDSTOCKS [63] [64]

Biodiesel feedstock	Percentage FFA
Refined vegetable oils	<0.05
Crude vegetable oils	0.3–0.7
Restaurant waste grease	2–7
Yellow grease	<15
Animal fat	5–30
Brown grease	>15
Trap grease	40–100

One of the most widely used methods for treating biodiesel feedstocks with higher FFA content is acid catalysis. Acid catalysis typically uses a strong acid such as sulfuric acid to catalyze the esterification of the FFAs and the transesterification of the triglycerides. The simplified form of the esterification process is given below in Equation 2. Acid esterification can be applied to feedstocks with FFA contents above 5%. Because the transesterification of triglycerides is slow under acid catalysis, a technique commonly used to overcome the reaction rate issue is to first convert the FFAs through an acid esterification (also known as an acid ''pretreatment'' step), and then follow-up with the traditional base-catalyzed transesterification of triglycerides. See Figure 2 for a general flow diagram of the acid esterification and subsequent transesterification biodiesel process.

Equation 2: Esterification

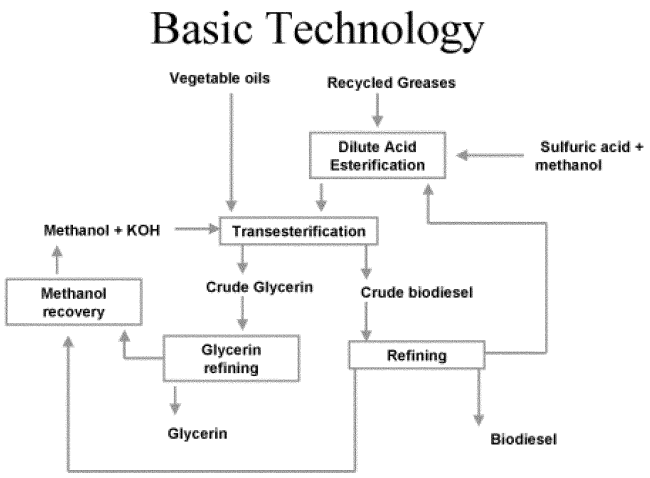
$$\text{Free Fatty Acid (Acid)} + \text{Methanol (Alcohol)} \xrightarrow[\text{(catalyst)}]{} \text{Methyl Ester (Ester)} + \text{Water}$$

[62] Commonly used base catalysts include sodium hydroxide (NaOH), potassium hydroxide (KOH) and sodium methoxide ($NaOCH_3$).

[63] Van Gerpen, J., Shanks, B., Pruszko, R., Clements, D., Knothe, G., ''Biodiesel Production Technology,'' NREL/SR–510–36244, July 2004.

[64] Van Gerpen, J., ''Used and Waste Oil and Grease for Biodiesel,'' NC State University A&T State University Cooperative Extension, *http://www.extension.org/pages/Used_and_Waste_Oil_and_Grease_for_Biodiesel.*

Figure 2: Process Description for Acid Esterification and Transesterification



Source: http://www1.eere.energy.gov/biomass/abcs_biofuels.html#biodprod

Under the RFS2 final rule, biodiesel from biogenic waste oils/fats/greases qualifies for D-Codes 4 and 5 using a ''transesterification'' process. This conclusion was based on the analysis of yellow grease as a feedstock in a process where there was an acid ''pretreatment'' or ''esterification'' process to treat the FFAs contained in the feedstock. In fact, one of the material inputs assumed in the modeling for the final RFS2 rule yellow grease pathway is sulfuric acid, which is the catalyst commonly used for acid esterification. However, we had not stipulated ''esterification'' as a qualified production process in Table 1 to § 40 CFR 80.1426. We believe this ambiguity could unnecessarily cause confusion as to whether esterification can also be used for the production of biodiesel under the currently approved pathways.

Since the biodiesel modeling completed for the final RFS2 rule actually includes esterification upstream of the transesterification process, we find it appropriate to clarify Table 1 to § 40 CFR 80.1426 to include ''esterification'' as a qualified process in which to produce biodiesel. As the modeling for yellow grease met an 86% GHG reduction emissions level, and yellow grease is typically <15% FFA content, it is reasonable to conclude that esterification and subsequent transesterification with a yellow grease feedstock containing FFAs at the very least up to 15% can meet the GHG reduction threshold for biomass-based diesel and advanced biofuel of 50%.

As noted in Table 15, however, there are feedstocks that may contain even higher levels of FFAs. As described below, EPA has evaluated the use of these higher FFA feedstocks to make biodiesel and has determined that use of such feedstocks also results in a biodiesel with lifecycle GHG emissions at least 50% less than that of conventional fuel.

The National Biodiesel Board (NBB) has conducted a comprehensive survey of the actual energy used by commercial biodiesel production plants in the U.S.[65] The survey depicts the amount of energy and incidental process materials such as acids used to produce a gallon of biodiesel. The survey data returned represents 37% of the surveyed 230 NBB biodiesel members in 2008 and includes producers using a variety of virgin oils and recycled or reclaimed fats and oils. While there is no specific data on the FFA content of the feedstocks used, the feedstocks did include reclaimed greases which represent the feedstocks which typically have the highest FFA content. As the data is partially aggregated, we used the maximum surveyed electricity and natural gas used at the facilities and a high estimate of ''materials used'' based on a sum of industry averages for all process materials for calculating potential GHG emissions. Even though some of the facilities might be processing feedstocks with relatively low FFA content, we believe that using these maximum observed inputs for energy used plus a high estimate for process materials used will estimate the highest GHG emissions profile for biodiesel production GHG emissions. When combined with the feedstock GHG emissions impact (see discussion below), the results still predict a GHG emissions reduction comfortably exceeding 50% as compared to the petroleum fuel it displaces. Therefore, there is little risk in predicting that any facility that utilizes esterification and feedstock over the range of likely FFA content can meet the 50% biomass-based diesel and advanced biofuel threshold.

According to the survey, the maximum electricity use for a producer reached as high as 3,071 Btu per gallon biodiesel. This is about 5 times higher than the industry average. The maximum natural gas usage for a producer reached as high as 12,324 Btu per gallon biodiesel, which is about 3.5 times higher than the industry average. For ''materials used'' only an industry average for each material was provided in the survey. Therefore, as a conservative estimate, we totaled all the average material inputs to equal 0.51 kg/gal biodiesel.[66] We believe that this is conservative because not all facilities are likely to use each and every one of the process materials listed in the survey (*e.g.,* we totaled all the acids

[65] National Biodiesel Board, Comprehensive Survey on Energy Use for Biodiesel Production (2008) *http://www.biodiesel.org/news/RFS/rfs2docs/NBB%20Energy%20Use%20Survey%20FINAL.pdf.*

[66] The material inputs include methanol, sodium methylate, sodium hydroxide, potassium hydroxide, hydrochloric acid, sulfuric acid, phosphoric acid, and citric acid. The majority of material input is from methanol.

used even though a facility is not likely to use each different acid). Thus, our estimate of materials used will estimate a level of maximum usage of materials at a given facility. In addition, we did not include a glycerin co-product credit when calculating emissions since the esterification reaction does not produce glycerin (see Equation 2). Using the same methodology as was used for the yellow grease modeling under RFS2, but using the high energy and materials use assumptions per the above discussion and omitting the glycerin co-product credit, we estimate the emissions from biodiesel processing at 23,708 gCO_2eq per mmBtu of biodiesel. The estimated GHG emissions reduction for the entire process is −71%. Since the GHG threshold is at −50% for biomass-based diesel and advanced biofuel, we believe that there is a large enough margin in the results to reasonably conclude that biodiesel using esterification of specified feedstocks with any level of FFA content meets the biomass-based diesel and advanced biofuel 50% lifecycle GHG reduction threshold. Therefore, we are including the process ''esterification'' as an approved biodiesel production process in Table 1 to § 40 CFR 80.1426. In addition, consistent with the modeling conducted for RFS2, we interpret the RFS regulations as they existed prior to today's rule as including a direct esterification process as part of the biodiesel pathways for which only ''trans-esterification'' was specifically referenced in Table 1 to § 40 CFR 80.1426.

V. Additional Changes to Listing of Available Pathways in Table 1 of 80.1426

We are also finalizing two changes to Table 1 to 80.1426 that were proposed on July 1, 2011 (76 FR 38844). The first change adds ID letters to pathways to facilitate references to specific pathways. The second change adds ''rapeseed'' to the existing pathway for renewable fuel made from canola oil.

On September 28, 2010, EPA published a ''Supplemental Determination for Renewable Fuels Produced Under the Final RFS2 Program from Canola Oil'' (FR Vol. 75, No. 187, pg 59622–59634). In the July 1, 2011 NPRM (76 FR 38844) we proposed to clarify two aspects of the supplemental determination. First we proposed to amend the regulatory language in Table 1 to § 80.1426 to clarify that the currently-approved pathway for canola also applies more generally to rapeseed. While ''canola'' was specifically described as the feedstock evaluated in the supplemental determination, we had not intended the supplemental determination to cover just those varieties or sources of rapeseed that are identified as canola, but to all rapeseed. As described in the July 1, 2011 NPRM, we currently interpret the reference to ''canola'' in Table 1 to § 80.1426 to include any rapeseed. To eliminate ambiguity caused by the current language, however, we proposed to replace the term ''canola'' in that table with the term ''canola/rapeseed''. Canola is a type of rapeseed. While the term ''canola'' is often used in the American continent and in Australia, the term ''rapeseed'' is often used in Europe and other countries to describe the same crop. We received no adverse comments on our proposal, and thus are finalizing it as proposed. This change will enhance the clarity of the regulations regarding the feedstocks that qualify under the approved canola biodiesel pathway.

Second, we wish to clarify that although the GHG emissions of producing fuels from canola feedstock grown in the U.S. and Canada was specifically modeled as the most likely source of canola (or rapeseed) oil used for biodiesel produced for sale and use in the U.S., we also intended that the approved pathway cover canola/rapeseed oil from other countries, and we interpret our regulations in that manner. We expect the vast majority of biodiesel used in the U.S. and produced from canola/rapeseed oil will come from U.S. and Canadian crops. Incidental amounts from crops produced in other nations will not impact our average GHG emissions for two reasons. First, our analyses considered world-wide impacts and thus considered canola/rapeseed crop production in other countries. Second, other countries most likely to be exporting canola/rapeseed or biodiesel product from canola/rapeseed are likely to be major producers which typically use similar cultivars and farming techniques. Therefore, GHG emissions from producing biodiesel with canola/rapeseed grown in other countries should be very similar to the GHG emissions we modeled for Canadian and U.S. canola, though they could be slightly (and insignificantly) higher or lower. At any rate, even if there were unexpected larger differences, EPA believes the small amounts of feedstock or fuel potentially coming from other countries will not impact our threshold analysis. Therefore, EPA interprets the approved canola pathway as covering canola/rapeseed regardless of country origin.

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

This action is not a ''significant regulatory action'' under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011).

B. Paperwork Reduction Act

This action does not impose any new information collection burden. The corrections, clarifications, and modifications to the final RFS2 regulations contained in this rule are within the scope of the information collection requirements submitted to the Office of Management and Budget (OMB) for the final RFS2 regulations.

OMB has approved the information collection requirements contained in the existing regulations at 40 CFR part 80, subpart M under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* and has assigned OMB control numbers 2060– 0637 and 2060–0640. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of 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; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this action on small entities, I certify that this rule will not have a significant economic impact on a substantial number of small entities. This rule will not impose any new requirements on small entities. The

relatively minor corrections and modifications this rule makes to the final RFS2 regulations do not impact small entities.

D. Unfunded Mandates Reform Act

This rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. We have determined that this action will not result in expenditures of $100 million or more for the above parties and thus, this rule is not subject to the requirements of sections 202 or 205 of UMRA.

This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. It only applies to gasoline, diesel, and renewable fuel producers, importers, distributors and marketers and makes relatively minor corrections and modifications to the RFS2 regulations.

E. Executive Order 13132 (Federalism)

This action 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. This action only applies to gasoline, diesel, and renewable fuel producers, importers, distributors and marketers and makes relatively minor corrections and modifications to the RFS2 regulations. Thus, Executive Order 13132 does not apply to this action.

F. Executive Order 13175 (Consultation and Coordination With Indian Tribal Governments)

This rule does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It applies to gasoline, diesel, and renewable fuel producers, importers, distributors and marketers. This action makes relatively minor corrections and modifications to the RFS regulations, and does not impose any enforceable duties on communities of Indian tribal governments. Thus, Executive Order 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

EPA interprets EO 13045 (62 FR 19885, April 23, 1997) as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the EO has the potential to influence the regulation. This action is not subject to EO 13045 because it does not establish an environmental standard intended to mitigate health or safety risks.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This rule is not subject to Executive Order 13211 (66 FR 18355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law 104–113, 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 action does not involve technical standards. Therefore, EPA did not consider the use of any voluntary consensus standards.

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 has determined that this rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. These amendments would not relax the control measures on sources regulated by the RFS regulations and therefore would not cause emissions increases from these sources.

K. Congressional Review Act

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

VII. Statutory Provisions and Legal Authority

Statutory authority for the rule finalized today can be found in section 211 of the Clean Air Act, 42 U.S.C. 7545. Additional support for the procedural and compliance related aspects of today's rule, including the 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, Administrative practice and procedure, Agriculture, Air pollution control, Confidential business information, Diesel Fuel, Energy, Forest and forest products, Fuel additives, Gasoline, Imports, Labeling, Motor vehicle pollution, Penalties, Petroleum, Reporting and recordkeeping requirements.

Dated: November 30, 2011.

Lisa P. Jackson,

Administrator.

For the reasons set forth in the preamble, 40 CFR part 80 is 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, 7521(1), 7545 and 7601(a).

■ 2. Section 80.1401 is amended by addition of the following definitions of ''Renewable Gasoline'' and ''Renewable Gasoline Blendstock'' in alphabetical order to read as follows:

§ 80.1401 Definitions.

* * * * *

Renewable gasoline means renewable fuel made from renewable biomass that is composed of only hydrocarbons and which meets the definition of gasoline in § 80.2(c).

Renewable gasoline blendstock means a blendstock made from renewable biomass that is composed of only hydrocarbons and which meets the definition of gasoline blendstock in § 80.2(s).

* * * * *

■ 3. Section 80.1426 is amended by revising Table 1 in paragraph (f)(1) to read as follows:

§ 80.1426 How are RINs generated and assigned to batches of renewable fuel by renewable fuel producers or importers?

* * * * *

(f) * * *

(1) * * *

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
A Ethanol	Corn starch	All of the following: Dry mill process, using natural gas, biomass, or biogas for process energy and at least two advanced technologies from Table 2 to this section.	6
B Ethanol	Corn starch	All of the following: Dry mill process, using natural gas, biomass, or biogas for process energy and at least one of the advanced technologies from Table 2 to this section plus drying no more than 65% of the distillers grains with solubles it markets annually.	6
C Ethanol	Corn starch	All of the following: Dry mill process, using natural gas, biomass, or biogas for process energy and drying no more than 50% of the distillers grains with solubles it markets annually.	6
D Ethanol	Corn starch	Wet mill process using biomass or biogas for process energy.	6
E Ethanol	Starches from crop residue and annual covercrops	Fermentation using natural gas, biomass, or biogas for process energy.	6
F Biodiesel, renewable diesel, jet fuel and heating oil.	Soy bean oil; Oil from annual covercrops; Algal oil; Biogenic waste oils/fats/greases; Non-food grade corn oil; Camelina oil.	One of the following: Trans-Esterification, Esterification Hydrotreating Excluding processes that co-process renewable biomass and petroleum.	4
G Biodiesel, heating oil	Canola/Rapeseed oil	Trans-Esterification using natural gas or biomass for process energy.	4
H Biodiesel, renewable diesel, jet fuel and heating oil.	Soy bean oil; Oil from annual covercrops; Algal oil; Biogenic waste oils/fats/greases; Non-food grade corn oil Camelina oil.	One of the following: Trans-Esterification, Esterification Hydrotreating Includes only processes that co-process renewable biomass and petroleum.	5
I Naphtha, LPG	Camelina oil	Hydrotreating	5
J Ethanol	Sugarcane	Fermentation	5
K Ethanol	Cellulosic Biomass from crop residue, slash, pre-commercial thinnings and tree residue, annual covercrops, switchgrass, miscanthus, napiergrass, giant reed, and energy cane; cellulosic components of separated yard waste; cellulosic components of separated food waste; and cellulosic components of separated MSW.	Any	3
L Cellulosic Diesel, jet fuel and heating oil.	Cellulosic Biomass from crop residue, slash, pre-commercial thinnings and tree residue, annual covercrops, switchgrass, miscanthus, napiergrass, giant reed and energy cane; cellulosic components of separated yard waste; cellulosic components of separated food waste; and cellulosic components of separated MSW.	Any	7

TABLE 1 TO § 80.1426—APPLICABLE D CODES FOR EACH FUEL PATHWAY FOR USE IN GENERATING RINS—Continued

Fuel type	Feedstock	Production process requirements	D-Code
M Renewable Gasoline and Renewable Gasoline Blendstock.	Cellulosic Biomass from crop residue, slash, pre-commercial thinnings, tree residue, annual cover crops; cellulosic components of separated yard waste; cellulosic components of separated food waste; and cellulosic components of separated MSW.	Catalytic Pyrolysis, Gasification and Upgrading, Direct Fermentation, Fermentation and Upgrading, all utilizing natural gas, biogas, and/or biomass as the only process energy sources. Any process utilizing biogas and/or biomass as the only process energy sources.	3
N Butanol	Corn starch	Fermentation; dry mill using natural gas, biomass, or biogas for process energy.	6
O Ethanol, renewable diesel, jet fuel, heating oil, and naphtha.	The non-cellulosic portions of separated food waste.	Any	5
P Biogas	Landfills, sewage waste treatment plants, manure digesters.	Any	5

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[FR Doc. 2011–31580 Filed 1–4–12; 8:45 am]

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