

Biofuels and Greenhouse Gas Emissions on a Collision Course

by Dr. Robert Wisner

The Energy Independence and Security Act (EISA) of 2007¹ requires a gradual increase in the volume of various kinds of biofuels to be blended with US motor fuels in the next several years. The gradual increase was designed to provide time for technology development and industry growth. At the same time, the EISA—unless modified—requires a one-step adjustment in greenhouse gas (GHG) reductions, rather than a gradual phase-in to reflect less than instantaneous technological progress. The EISA also implicitly assumes that greenhouse gas (GHG) emissions from the baseline that is used to evaluate biofuels will be unchanged in the future. It is debatable whether that assumption is valid.

These two different sets of mandates are now on a collision course. If changes are not made, their different paths could slow or halt the growth of some parts of the biofuels industry. The sectors of the industry to be most immediately affected are Midwest corn-starch ethanol and biodiesel from vegetable oils. As regulatory activity on the GHG issues has progressed, two different government agencies have become involved. One is the US Environmental Protection Agency (EPA), which has recently announced proposed national assessments on GHG emissions. The other is the Air Resources Board of the California Environmental Protection Agency. California has decided to move ahead more quickly than at the national level in establishing regulations to reduce GHG emissions and has developed assessments of GHG emissions for several different kinds of biofuels.

The proposed California regulations take on added significance when the biofuels industry considers that (1) California is the largest potential market in the US for biofuels and (2) at least 13 other states are considering adoption of its standards. President Obama has expressed a desire for a uniform national standard relating to GHG emissions. That raises the possibility that California's standards could become the US standards. A key issue in both the California and EPA GHG assessments of biofuels is the impact of "indirect land use emissions impacts."

Indirect land use stems from the presumption that when an acre of land is diverted from production for feed and food to biofuels, that at least a portion of that acre will be added to food and feed production somewhere else, either in the US or abroad. It is assumed that additional cropland will be needed and that it is most likely to come from diversion of rainforest or pasture in tropical areas to food and feed production. In some cases, if there is an indirect land use impact, it could come from conversion of pasture, forage, or conservation reserve land in the US

to cropland. Thus, the indirect land use measurement represents the estimated net change in GHG emissions or CO₂ sequestering done by the change in land use somewhere else in the world.

The amount of indirect land use change needed for biofuels and ways of measuring resulting emissions impacts from land-use changes are being intensely debated. Longer-term technological changes that bring increased crop yields per acre, changes in livestock and poultry feed conversion efficiency that reduce feed needs per animal, the amount of crop residue left on soils, and other factors will affect indirect land use emissions. Much more research is needed on these issues to accurately measure indirect land use impacts. Also, direct emissions from biofuels refineries are being reduced over time through technological advances.

California GHG Emissions Regulations²

The California Air Resources Board (CARB) of the California Environmental Protection Agency is the agency responsible for implementing GHG emission standards required by the state government. As shown in Table 1, California's low carbon fuel standard (LCFS) reduces the allowable amount of CO₂ emissions each year from 2011 through 2020, until average emissions from gasoline and diesel fuel are reduced by 10% from the current baseline level. Emissions are measured per unit of energy of each fuel so that variations in energy content per gallon of various fuels are taken into account. Petroleum-based gasoline and diesel fuel are used for the baselines from which other fuels will be compared. Reductions are not required for individual shipments of fuel. However, individual regulated firms are

Table 1. Year-by-Year Proposed California CO₂ Emissions Reductions from the Gasoline & Petroleum-diesel Fuel Baselines.

<u>Year</u>	<u>% change from baseline</u>
2010	<i>Reporting only</i>
2011	0.25%
2012	0.50%
2013	1.00%
2014	1.50%
2015	2.50%
2016	3.50%
2017	5.00%
2018	6.50%
2019	8.00%
2020 & later yrs.	10.00%

Source: Derived from Table ES-3, page ES-9, California EPA, Air Resources Board.
*Proposed Regulations to Implement the Low Carbon Fuel Standard, Vol. I.

Table 2. California Estimated CO₂ Equivalent Emissions by Fuel Type¹

Fuel Type	Fuel Details ²	CO ₂ Emissions measurements ¹			
		Direct Emissions	Indirect Land Use Impact	Total	
Gasoline	Baseline— with average crude oil delivered to California refineries and average CA refinery efficiencies	95.9	0	95.9	
	California E-10 with average Midwest Ethanol	96.1	---	96.1	
E-10	E -10 with 80% Midwest ethanol + 20% California corn ethanol (dry mill, wet DGS)	95.9	---	95.9	
	Midwest average; 80% Dry Mill; 20% Wet Mill; Dry DGS	69.4	30	99.4	
	California average; 80% Midwest Average; 20% California; Dry Mill; Wet DGS; NG	65.7	30	95.7	
	California; Dry Mill; Wet DGS; NG	50.7	30	80.7	
Ethanol from Corn	Midwest; Dry Mill; Dry DGS; NG	68.4	30	98.4	
	Midwest; Wet Mill; 60% NG; 40% coal	75.1	30	105.1	
	Midwest; Dry Mill; Wet; DGS	60.1	30	90.1	
	California; Dry Mill; Dry DGS; NG	58.9	30	88.9	
	Midwest; Dry Mill; Dry DGS; 80% NG; 20% Biomass	63.6	30	93.6	
	Midwest; Dry Mill; Wet DGS; 80% NG; 20% Biomass	56.8	30	86.8	
	California; Dry Mill; Dry DGS; 80% NG; 20% Biomass	54.2	30	84.2	
	California; Dry Mill; Wet DGS; 80% NG; 20% Biomass	47.4	30	77.4	
	Brazil Eth.	Brazilian sugarcane using avg. production processes	27.4	46	73.4
		California NG via pipeline; compressed in California	67.7	0	67.7
Natural Gas	North American NG delivered via pipeline; compressed in Cal.	68.0	0	68.0	
	Landfill gas (bio-methane) cleaned to NG quality; compressed in Cal.	11.3	0	11.3	
	Electricity	Cal. Avg. electricity mix (Adjust. For 3x vehicle effic. Vs. gasoline) ³	124.1	0	41.4
Cal. marginal electricity mix - natural gas & renewable energy sources ³		104.7	0	34.9	
Hydrogen	Compressed H ₂ from central reforming of NG	142.2	0	61.8	
	Liquid H ₂ from central reforming of NG ⁴	133.0	0	57.8	
	Compressed H ₂ from on-site reforming of NG ⁴	98.3	0	42.7	
	Compressed H ₂ from on-site reforming + renewable feedstocks ⁴	76.1	0	33.1	

¹Carbon Intensity Values, measured as grams of CO₂ equivalent per equivalent per megajoule (MJ).

²Adapted from Table IV-1, California Environmental Protection Agency, Air Resources Board, Proposed Regulations to Implement the Low Carbon Fuel Standard, Volume I, March 2009 (Released 4/23/09). For a more complete description of fuel types and emissions measurements, see this report.

³Total emissions reflect adjustment for a vehicle fuel efficiency factor of 3.

⁴Total emissions reflect adjustment for a vehicle fuel efficiency factor of 2.3.

to be required to reduce GHG emissions from their total annual volumes by these percentages.

Required percentage reductions decline quite gradually for the first two years, but the rate of decrease accelerates starting in 2013. The initial gradual decline provides a limited time for the petroleum-based and renewable fuels industries to adjust before more extreme reductions are required.

Table 2 shows CARB’s estimated carbon emissions intensity of various biofuels by direct and indirect land use impacts, as well as the gasoline baseline emissions. Note that each type of ethanol has a rating for indirect land use while the baseline and some other fuel alternatives do not. This category is the controversial indirect land use impact rating, which has a large negative impact on the ability of ethanol to meet proposed future California GHG standards. Without this category, the ethanol fuels would be in a much stronger position relative to gasoline than current assessments indicate. Also note that ethanol from cellulose feedstocks is not included because commercially applicable technology for its production is not yet available. [Editor’s note: However, see the article on page 11.]

The California Air Resources Board (CARB) identifies several types of ethanol, with CO₂ emissions varying depending on where the fuel was produced, whether its co-product, distillers grain and solubles, (DGS) is dried or shipped wet from the plant, and what fuel type or types were used for the plant’s energy source. The location of production is assumed to impact emissions because of its relationship to transport needs and emissions.

Alternative fuel types include coal, natural gas (NG), biomass, or some combination of these. Note that coal-fired plants are at the greatest disadvantage relative to other biofuels.

Table 2 shows total CO₂ emissions for various types of fuels as a percent of the baseline, with and without the indirect land use effect. We have included a number of alternatives to ethanol and gasoline, some of which are not from renewable sources. We show them in Tables 1 and 2 because they will be strong future competitors with ethanol in the effort to control GHGs. Some of these alternatives—for example, compressed natural gas—are already being used here and in other countries. They may or may not be competitive with ethanol in price, depending on future costs of natural gas and electricity.

Midwest Ethanol Indicated to be at a Disadvantage

Table 3 shows CARB’s estimated carbon emissions intensity of various biofuels as percentages of the gasoline baseline. Note that each type of ethanol has a rating for indirect land use. This category is the controversial indirect land use impact rating. Without this category, the ethanol fuels would be in a much stronger position relative to gasoline than current assessments indicate. For every ethanol alternative, California ethanol is given a more favorable GHG rating than that from the Midwest. Also note that ethanol from cellulose feedstocks is not included because commercially applicable technology for its production is not yet available.

Table 3. California Estimated CO₂ Equivalent Emissions as % of the Baseline¹

Fuel Type	Fuel Details ²	CO ₂ Emissions % of Baseline ¹	
		Without Indirect Land Use	With Indirect Land Use
Gasoline	Baseline— with average crude oil delivered to California refineries and average CA refinery efficiencies	100.0%	100.0%
E-10	California E-10 with average Midwest Ethanol	100.2%	100.2%
	E -10 with 80% Midwest ethanol + 20% California corn ethanol (dry mill, wet DGS)	100.0%	100.0%
	Midwest average; 80% Dry Mill; 20% Wet Mill; Dry DGS	72.4%	103.7%
	California average; 80% Midwest Average; 20% California; Dry Mill; Wet DGS; NG	68.5%	99.8%
Ethanol from Corn	California; Dry Mill; Wet DGS; NG	52.9%	84.2%
	Midwest; Dry Mill; Dry DGS; NG	71.4%	102.6%
	Midwest; Wet Mill; 60% NG; 40% coal	78.3%	109.6%
	Midwest; Dry Mill; Wet; DGS	62.7%	94.0%
	California; Dry Mill; Dry DGS; NG	61.4%	92.7%
	Midwest; Dry Mill; Dry DGS; 80% NG; 20% Biomass	66.3%	97.6%
	Midwest; Dry Mill; Wet DGS; 80% NG; 20% Biomass	59.3%	90.5%
	California; Dry Mill; Dry DGS; 80% NG; 20% Biomass	56.5%	87.8%
Brazil Eth.	California; Dry Mill; Wet DGS; 80% NG; 20% Biomass	49.4%	80.7%
	Brazilian sugarcane using avg. production processes	28.6%	76.6%
Natural Gas	California NG via pipeline; compressed in California	70.6%	70.6%
	North American NG delivered via pipeline; compressed in Cal.	70.9%	70.9%
	Landfill gas (bio-methane) cleaned to NG quality; compressed in Cal.	11.7%	11.7%
Electricity	Cal. Avg. electricity mix (Adjust. For 3x vehicle effic. Vs. gasoline)	43.2%	43.2%
	Cal. marginal electricity mix - natural gas & renewable energy sources	36.4%	36.4%
Hydrogen	Compressed H ₂ from central reforming of NG	64.5%	64.5%
	Liquid H ₂ from central reforming of NG	60.3%	60.3%
	Compressed H ₂ from on-site reforming of NG	44.6%	44.6%
	Compressed H ₂ from on-site reforming + renewable feedstocks	34.5%	34.5%

¹Carbon Intensity Values, measured as grams of CO₂ equivalent per equivalent per megajoule (MJ).

²Adapted from Table IV-1, California Environmental Protection Agency, Air Resources Board, Proposed Regulations to Implement the Low Carbon Fuel Standard, Volume I, March 2009 (Released 4/23/09). For a more complete description of fuel types and emissions measurements, see this report.

Figure 1 shows how selected alternative fuels compare with the baseline (gasoline) from 2011 through 2020, as allowable emissions of GHG decline in future years. Note that for each year including 2011, Midwest ethanol produced from plants using either 100% natural gas, or coal for 40% and natural gas for 60% of their energy requirements, with dry distillers grain would fail to meet the proposed California standards. From 2015 onward, E-10 made entirely from typical Midwest ethanol or from 80% Midwest ethanol and 20% typical California ethanol would fail to meet the proposed standards. Midwest ethanol produced with natural gas-fired plants and producing only wet distillers grain would meet the standards from 2011 through 2017 but would fail to meet them in later years. In contrast, California ethanol plants producing only wet distillers grain and using natural gas for energy would meet the standards throughout the period, as would Brazilian sugar cane ethanol. Thus, application of the proposed standards would place Midwest corn-starch ethanol plants at a distinct disadvantage relative to California plants and Brazil. Both of these sources of ethanol would be at a large disadvantage to compressed gas from landfill sources.

Figure 2 shows ratings for additional types of bio-fuels, including ethanol from Midwestern and California plants that use biomass for a portion of their energy source. Midwestern plants using biomass for 20% of their energy source, natural gas for 80%, and producing only dry distillers grain would meet the California standards through 2014 but not in later years. If these same plants produced only wet distillers grain, they would meet the proposed California GHG emissions standards only until

2019. Equivalent California plants producing either wet or dry DGS would continue to meet the standards through 2020. Even so, California ethanol plants would face intense GHG emissions competition from vehicle fuel produced by compressed natural gas and electricity—especially electricity produced from natural gas and renewable energy sources. Market share of these various fuels would depend not only on traditional cost competitiveness but GHG emissions as well.

Some Implications

If these proposed regulations are implemented in their present form, the ethanol industry will face a critically important new

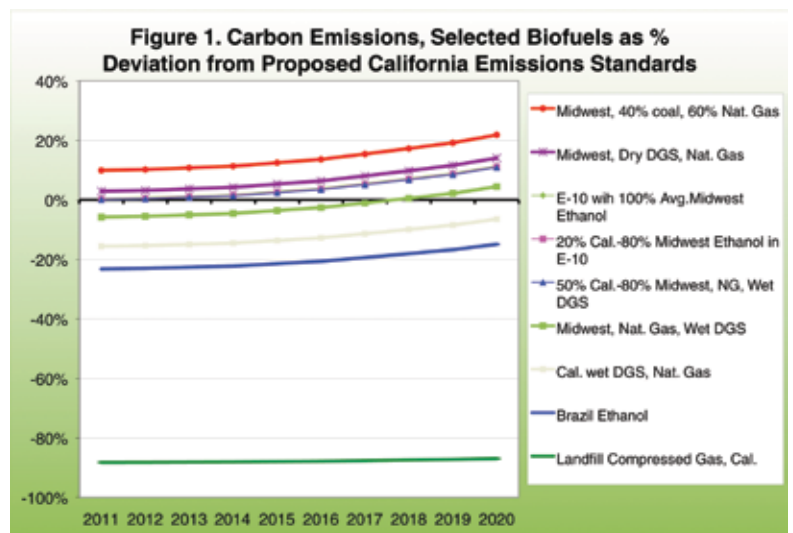
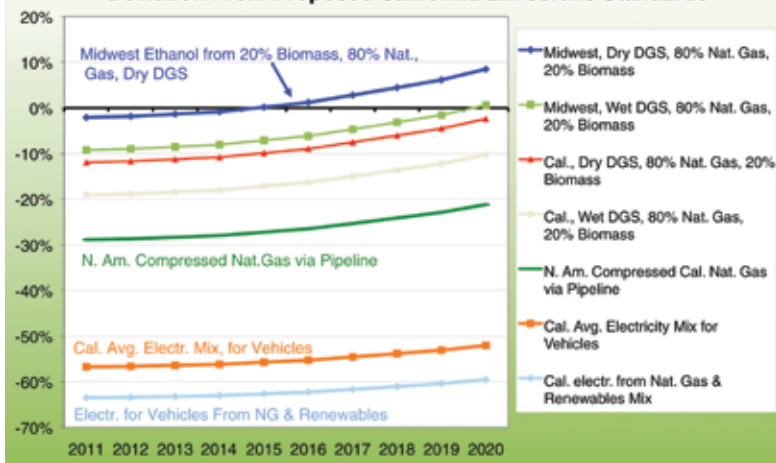


Figure 2. CO₂ Equivalent Emissions, Other Biofuels as % Deviation From Proposed California Emissions Standards



dimension in its competitiveness in addition to traditional price and cost issues. This analysis indicates that even if Midwest ethanol plants have cost advantages over California plants, the proposed regulations would be expected to keep them from marketing their ethanol in California in future years. How soon their California markets would be affected would depend on whether they produce only wet DGS or dry a portion of the co-product. Midwest plants using biomass for a portion of their energy source

could delay loss of the California market for a few years. At the same time, extensive use of biomass such as corn stover as an ethanol plant energy source could divert supplies from their planned future use as feedstock for the cellulose ethanol industry.

The proposed California regulations hint that in California, ethanol may be viewed as a temporary transitional fuel, to be replaced by electric-powered vehicles and those using various forms of compressed gas for fuel in the future. Extensive analysis of potential supplies and cost of these alternative fuels is needed before a determination can be made of how much motor fuel can be generated from these sources.

A key determinant of ethanol’s disadvantage in the California motor fuel market is the estimated indirect land use impact. There is considerable disagreement in the scientific community on how to accurately assess this impact and to what extent this factor is needed. The US historically has had large grain surplus production capacity as productivity increases from new technology have outpaced food and feed demand growth. Along with a number of other considerations, future prospects for productivity in grain production needs to be included in the assessment, along with probable future technological improvements in energy efficiency of ethanol production.

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ASA Says EPA Proposals Would Harm Soy Biodiesel Industry

On May 6, the American Soybean Association (ASA) submitted comments to the House Agriculture Subcommittee on Conservation, Credit, Energy and Research regarding the impact of the indirect land use and renewable biomass provisions in the U.S. Environmental Protection Agency’s (EPA) expanded Renewable Fuel Standard (RFS-2). According to the ASA, there are numerous potential flaws in the approach EPA is using for indirect land use changes in its proposed rule. Further, there are numerous factors that ASA believes refute the possibility that significant international indirect land use change would result from the relatively small increase in U.S. biodiesel production called for under the RFS-2.

“The approach EPA has used in its proposed rule on RFS-2 implementation is significantly flawed and would do unnecessary and irreversible harm to the competitive position of the U.S. soy biodiesel industry,” said ASA President Johnny Dodson, a soybean producer from Halls, Tennessee. “EPA’s projections of indirect international land use changes resulting from a quite small increase in biodiesel production are built on faulty assumptions, flawed analysis, and misplaced penalties.”

ASA included a detailed list of the flaws in EPA’s assumptions in its comments to the subcommittee. These comments are available at: www.SoyGrowers.com/policy/indirect.pdf.

When calculating the life cycle greenhouse gas (GHG) impact of biofuels, the statute directs EPA to consider direct and indirect emissions, including indirect land use, of all

stages of the fuel and feedstock production. The primary area of concern and disagreement has emerged over the international indirect land use assumptions that EPA has proposed to use in conducting its updated life cycle GHG analysis.

The ASA notes that land use change has been occurring around the world for some time, long before biodiesel was produced in the U.S. The EPA analysis uses land converted to cropland from 2001-2004 and extrapolates that into the future. Since there was very little U.S. soy biodiesel produced from 2001-2004, it is illogical how EPA justifies attributing future land conversion to soy biodiesel, according to the ASA.

“It was not the intent of Congress for soy biodiesel to be excluded from the RFS-2,” Dodson said. “If soy biodiesel is excluded, the biomass-based diesel schedule under RFS-2 cannot be achieved. There are simply not enough of other biodiesel feedstocks to produce the amount of biodiesel called for in the RFS-2.”

ASA believes that the EPA must use the rulemaking process to correct and improve the life cycle analysis that will ultimately be used to implement the RFS-2 program.

“ASA looks forward to working with Congress and coordinating with industry partners and the academic and scientific community to provide the information to demonstrate that U.S. soy biodiesel is the cleanest burning biofuel available today, and is not responsible for international land use changes,” Dodson said.

Biofuels and Greenhouse Gas *(continued from page 5)*

Conclusions

California’s policies that are designed to reduce greenhouse gas (GHG) emissions are of vital interest to the US biofuels industries. There is a strong chance that California’s proposed regulations for reducing carbon dioxide (CO₂) emissions from motor fuels will be applied nation-wide.³ The current version of California regulations as well as GHG reduction mandates from the Energy Independence and Security Act of 2007 and emerging regulations from the US Environmental Protection Agency are on a collision course with the ethanol blending mandates. The current direction of GHG emissions reductions policy will make it difficult to attain the sharply increased biofuels use levels that are mandated by 2007 energy legislation.

The California proposed regulations also put Midwest corn-starch ethanol at a substantial disadvantage relative to ethanol produced in California or Brazil in the nation’s potentially largest ethanol market. Midwest ethanol is at an even greater disadvantage relative to compressed natural gas, compressed landfill gas, electric vehicles, and possible future hydrogen-powered vehicles—from a GHG emissions standpoint. Ethanol could conceivably be more cost competitive than some of these alternatives (unless penalized by emissions taxes) but unable to compete because of estimated GHG emissions.

California’s initial version of proposed regulations does not include GHG emissions evaluations from biodiesel. However, preliminary reports from the US EPA hint that soy-based biodiesel may not fare well in the GHG evaluations because of indirect land use impacts.⁴ Indirect land use impacts are triggered if some portion of each acre of land shifted from feed and food use to fuel production needs to be replaced by other land brought into

production elsewhere in the world. Changing use of that other land may result in increased GHG emissions or reduced GHG sequestering by that land.

Indirect land use impact is an important component of the California estimated emissions disadvantage from corn-starch ethanol. Scientists and economists are not in universal agreement on ways of measuring this impact. Much more research is needed before universally acceptable indirect land use impact assessments are available. With the rapid rate at which GHG emissions policy is moving forward, there is an urgent need for more research on indirect land use impacts.

References

1. Energy Independence and Security Act of 2007.
2. California Environmental Protection Agency, Air Resources Board, Proposed Regulation to Implement the Low Carbon Fuel Standard, Volume I, March 5, 2009 with release date April 23, 2009.
3. David Shepardson, “White House to unveil new auto emissions standards,” *Detroit News*, May 18, 2009 indicates a universal US automobile tailpipe emissions policy is expected. This raises the possibility of a universal GHG emissions policy as well.
4. Jeanne Bernick, “EPA Rule Could Wreck Biofuel Competition,” *AgWeb.com*, May 19, 2009.

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