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2008 Environ. Res. Lett. 3 024003

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The effect of CO₂ regulations on the cost of corn ethanol production

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Received 7 January 2008
Accepted for publication 30 April 2008
Published 15 May 2008
Online at stacks.iop.org/ERL/3/024003

Abstract
To explore the effect of CO₂ price on the effective cost of ethanol production we have developed a model that integrates financial and emissions accounting for dry-mill corn ethanol plants. Three policy options are modeled: (1) a charge per unit of life cycle CO₂ emissions, (2) a charge per unit of direct biorefinery emissions only, and (3) a low carbon fuel standard (LCFS). A CO₂ charge on life cycle emissions increases production costs by between $0.005 and $0.008 l⁻¹ per $10 Mg⁻¹ CO₂ price increment, across all modeled plant energy systems, with increases under direct emissions somewhat lower in all cases. In contrast, a LCFS increases the cost of production for selected plant energy systems only: a LCFS requiring reductions in average fuel global warming intensity (GWI) with a target of 10% below the 2005 baseline increases the production costs for coal-fired plants only. For all other plant types, the LCFS operates as a subsidy. The findings depend strongly on the magnitude of a land use change adder. Some land use change adders currently discussed in the literature will push the GWI of all modeled production systems above the LCFS target, flipping the CO₂ price from a subsidy to a tax.

Keywords: ethanol, greenhouse gas emissions, life cycle assessment, low-carbon fuel standard

The authors dedicate this paper to Professor Alex Farrell of UC Berkeley: in memoriam.

1. Introduction

Carbon dioxide emissions from the transportation sector comprise about one third of total CO₂ emissions in the US, and 40% of the total in California. To help mitigate the climate change impact of this sector, the state of California is developing—and several other jurisdictions have proposed—policies to reduce the so-called ‘carbon intensity’ of transportation fuels, presently dominated by petroleum-based gasoline and diesel. These regulations would account for the emissions of greenhouse gases during all phases of the fuel cycle, including production, distribution, and use of all transportation fuels. At least 12 US states are currently considering the implementation of fuel standards based on California’s, though these may be superseded by a national standard [1]. Similar regulations have been proposed in British Columbia and the European Union.

While the term ‘carbon intensity’ is popular, it does not include non-CO₂ climate impacts, and could be misconstrued to include biogenic fuel carbon in the accounting. In this article, we use the term global warming intensity (GWI), defined here as the life cycle CO₂-equivalent greenhouse emissions of three greenhouse gases (CO₂, N₂O, and CH₄), weighted by their respective CO₂-equivalency (100 year global warming potential) values, per megajoule of delivered fuel [12].

In the near term, a primary strategy for producers of petroleum-based fuels to lower the average GWI of their product will be the blending of low GWI biofuels with gasoline and diesel. The demand for low GWI biofuels will likely result

3 Under the California LCFS, some fuels, notably diesel and electricity may be adjusted for the higher inherent efficiency of conversion to motive power in drive trains utilizing those fuels. See [11, 12] for details.
in ethanol markets shifting from uniform commodity pricing to quality-differentiated pricing based on the GWI of distinct fuel production pathways, with lower GWI biofuels commanding a price premium.

Given the high likelihood that greenhouse gas emissions will be regulated during the lifetime of most facilities in operation or under construction today, it is essential that biofuel producers incorporate into the financial calculus the effect of CO2 price on the cost of plant energy system alternatives.

Many life cycle energy and greenhouse gas (GHG) analyses of corn ethanol production have been published since the 1970’s (e.g., [3, 5, 10, 14, 22, 25, 26, 30, 31, 38, 39]), as have studies of ethanol production costs [13, 20, 21, 32, 16, 34, 33]. However, we are aware of no prior studies that integrate cost and emissions analyses by placing a price on CO2 emissions.

2. Methods

To explore the effect of CO2 price on ethanol production costs, we developed the Biofuels Emissions And Cost CONneXion (BEACCON) model, a spreadsheet model created in Microsoft Excel®. Using BEACCON, we analyze seven dry-grind ethanol energy system configurations fueled with coal, natural gas, and biomass comparing the per-gallon life cycle GHG emissions and cost of ethanol under a range of price assumptions for fuels and CO2 emissions.

The goal of the analysis is to understand the differential GHG emissions and production costs of each configuration. The analysis considers the emissions across the ethanol production chain of three greenhouse gases (CO2, N2O, and CH4), weighted by their 100 year global warming potentials [18].

The system boundaries include corn production and transport, conversion of corn to ethanol, and ethanol distribution. Corn production includes the energy and emissions associated with production and transportation of farm inputs such as fertilizer, pesticide, lime, and seed. Energy and emissions from the production of agricultural and bioenergy capital equipment is negligible and therefore not included [41]. Although there is significant variation in the on-farm energy use, irrigation patterns, and soil emissions of N2O in corn production, BEACCON treats all corn production as homogeneous, incorporating the life cycle GWI for average Midwest corn production and transportation from GREET 1.7. This value, 27 g CO2e MJ−1, is added to the specific life cycle GHG emissions for each plant configuration.

Land use change, including market-mediated effects induced by changes in cropping patterns, are potentially large enough to significantly alter the GWI of crop-based biofuels. However, lacking an accepted methodology to account for this effect, we have included in BEACCON only the small land use change factor included in GREET 1.7 (0.9 g CO2e MJ−1) for expansion of US corn ethanol production from 1.5 to 4 billion gal per year. In a sensitivity analysis, we consider alternative values for this factor.

2.1. Dry-mill energy systems

BEACCON models only the dry-mill corn ethanol process. All corn ethanol plants built in recent years or currently under construction use the dry-milling process [39]. The dry-mill configurations modeled are based on a 378.5 million l (100 million gal) per year capacity and 100% drying of co-produced distillers grains. The modeled plants differ by primary fuel (coal, natural gas, biomass), energy system configuration (combined heat and power systems or utility purchased electricity) and by construction class (retrofit versus new construction plants). The plant configurations assessed in the present study are shown along the X-axis of figures 1 and 2.

The primary contributors to the GWI of corn ethanol are corn farming and the thermal energy systems at ethanol plants. BEACCON incorporates the default corn farming energy and emissions from GREET 1.7. The three primary characteristics of a dry-mill energy system that affect the GWI of ethanol are thermal energy fuel choice, energy system configuration (i.e. CHP or non-CHP), and the GHG emissions factor for the local grid.

The life cycle GHG emissions for thermal energy production in BEACCON are based on two sources: we use the EPA’s AP-42 database for emissions factors of CO2, CH4, and N2O from combustion, while we rely on GREET for upstream emissions from the production and transport of fuels [36, 35]. These two factors are combined in BEACCON to produce life cycle GHG emissions factors per MJ of process fuel consumed at the dry mill.

Most ethanol dry mills purchase electricity from the local grid. An ethanol plant can reduce its use of purchased grid electricity by installing a combined heat and power (CHP) system, though this option is infrequently used. Of the 115 ethanol plants that were in operation in 2007, only seven plants (four natural gas and three coal-fired plants) utilize combined CHP technologies [6]. Substituting purchased electricity with on-site generation also alters the GWI from the energy system, especially when using natural gas-based CHP in a coal-dominated grid region.

BEACCON models the emissions for each grid region aggregated into North American Electricity Reliability Council (NERC) regions. The emissions factors in BEACCON are for electricity ‘at the plug’, including 8% transmission and distribution losses as per the GREET model [40]. The differences in final ethanol GWI vary by only about 2 g CO2/MJ (between about 2–4% of total emissions, depending on plant type) from California, which is in a low GWH emissions grid region, to Illinois, in a high emissions grid region. However, the potential reductions in GWI for implementing a CHP system depend on the relative emissions factors for fuel used at the plant fuel and local grid electricity.

5 The IPCC’s Fourth Assessment Report (2007) updates the GWP values, but as many of the BEACCON emissions factors are imported from GREET, which uses the 2001 GWP values, we use the 2001 values throughout BEACCON for consistency.
6 Depending on the baseline established, land use change may be the single most important factor in the GWI of corn ethanol. Land use change is discussed in section 4.1.
2.2. Financial assumptions

BEACCON models the cost of producing a gallon of denatured ethanol based on capital costs and plant operations and maintenance costs, including thermal fuel and electricity feedstock costs. BEACCON also includes the cost of CO$_2$ emissions under various policy alternatives.

The ethanol plant capital cost assumptions as well as the fuel and electricity requirements in BEACCON for the various 378.5 million liters per year ethanol plant energy systems are based on information provided by original equipment manufacturers [23]. Labor, permitting fees, and boiler/turbine maintenance fees are detailed in Mueller and Cuttica [23]. We assume a total plant capital cost of $145 million for a 378.5 million liter per year facility, or $0.38 l$^{-1}$ ($1.45 gal^{-1}$) of capacity [19].

Prices for production inputs are for the year 2006 [9, 7, 8]. The corn price and DDGS prices assumed in BEACCON are $0.18 kg^{-1}$ ($4.50 bu^{-1}$) and $145 Mg^{-1}$ ($132 ton^{-1}$), respectively. Fuel costs assumed for the state of Iowa are: $0.29 m^{-3}$ ($8.05/MMBtu) of natural gas, $28.37 Mg^{-1}$ ($25.73 ton^{-1}$) for Powder River Basin coal delivered to the plant, and $0.073 kWh^{-1}$ of electricity. Among all the input factors, only the recent rise in corn prices has had a large effect on the cost of producing ethanol: increasing corn price from $4.50 to $6.00 per bushel increases production costs by $0.14 l^{-1}$ ($0.54 gal^{-1}$). However, the associated rise in the price of DDGS from $132 to $170 ton^{-1}$ increases revenues by $0.03 l^{-1}$ ($0.12 gal^{-1}$), for a net increase in production costs of $0.11 l^{-1}$ ($0.42 gal^{-1}$).  

2.3. Greenhouse gas policies

The present study compares three types of GHG policies: (1) a charge per unit of life cycle CO$_2$ emissions, (2) a charge per unit of direct biorefinery emissions only, and (3) a low carbon fuel standard. A cap-and-trade system and a tax result in an essentially equivalent charge at any given CO$_2$ price, although the prior provides more certainty about emissions and the latter about costs [27]. For our modeling purposes, however, these two types of policies are equivalent since we model only the effect on the cost of production at a given price of CO$_2$. Rather than attempt to predict the price of CO$_2$, we use the model to find the price per metric tonne (Mg) of CO$_2$ that balances out the costs of various competing systems, for example the price of CO$_2$ at which a natural gas-fired plant becomes cheaper than a coal-fired plant.

Section 3.8 of the supporting materials (available at stacks.iop.org/ERL/3/024003) offers a more detailed sensitivity analysis.

Figure 1. Life cycle GHG emissions (g CO$_2$e MJ$^{-1}$) by plant type for Iowa for denatured ethanol including the default GREET value for land use change of 1 g CO$_2$e MJ$^{-1}$.
A fuel GWI standard with a non-zero baseline behaves very differently than a carbon charge. In particular, whereas a carbon charge increases the cost of all fuels with positive GWI ratings, a GWI standard such as the LCFS effectively taxes fuels with GWI ratings above the standard and subsidizes fuels with ratings below the standard [17].

The California LCFS will most likely include trading of emission reduction credits, giving regulated entities the option of reducing emissions through efficiency improvements, through blending lower GWI products, or through purchasing emission reduction credits [12]. Assuming a sufficiently liquid market for credits, the incremental value of lower GWI ethanol should be bounded by the price of credits since any gap between these prices would be eliminated through arbitrage. Low cost producers of high GWI ethanol may be able to bundle their product with credits to facilitate sale into regulated fuel markets.

Although the LCFS is an intensity-based system, credits in the LCFS market will need to be denominated in mass units (e.g., Mg of CO2) rather than in intensity units (e.g., g CO2/MJ). Each 1 g MJ⁻¹ reduction in ethanol GWI per liter is equivalent to about 22 g CO2e l⁻¹.⁸ A CO2 price of $50 Mg⁻¹ is therefore equivalent to $0.001 per unit of GWI per liter: a regulated entity should be indifferent between paying a premium of $0.50 kl⁻¹ ($0.004 gal⁻¹) of ethanol for each 1 g CO2e MJ⁻¹ reduction in GWI and buying credits at a price of $50/Mg CO2.

BEACCON combines the GWI estimate for each plant with an assumed price of CO2 to compute a total effective cost of production for each plant alternative. For the two carbon charge alternatives, the annual CO2-equivalent emissions (either life cycle or direct only) are multiplied by the cost of CO2 and added to the annual production costs. For the LCFS, the GWI of the fuel from each plant is subtracted from the assumed LCFS target of 79 g CO2e MJ⁻¹ and multiplied by the price of CO2 expressed in units of dollars per liter for a one gram CO2e MJ⁻¹ change, yielding a tax for fuels with GWI above the target and a subsidy for fuels with GWI below the target.

3. Results

Figure 1 shows the GWI (life cycle CO2-equivalent emissions per MJ of fuel) for seven ethanol dry-mill configurations compared to the GWI (including combustion) of conventional

Figure 2. Denatured ethanol production costs ($ per gasoline liter equivalent) under CO2 policy options for various plant types in Iowa, assuming $4.50 bu⁻¹ corn, a $50/Mg CO2 charge and an LCFS target of 79 g CO2e MJ⁻¹. Includes the default GREET value for land use change of 1 g CO2e MJ⁻¹.
gasoline. Combustion emissions of CO$_2$ are not counted for biofuels since the carbon in the fuel was removed from the atmosphere during photosynthesis. The GWI of ethanol is determined mainly by the primary fuel used to meet thermal demands at the plant. Ethanol produced in a coal-fired ethanol plant has approximately the same GWI as gasoline (92 g CO$_2$e MJ$^{-1}$), even when employing CHP. The GWI of ethanol produced in a natural gas-fired dry mill is about 30% lower than the GWI of gasoline.

In general, ethanol from CHP facilities has a lower GWI than ethanol from similarly-fueled non-CHP plants, at equal or lower costs. With CHP, a natural gas-fired ethanol plant in Iowa can similarly reduce the GWI of its product from 65 to 60 g CO$_2$e MJ$^{-1}$. A biomass-fired plant in that state can reduce its ethanol GWI from 45 to 36 g CO$_2$e MJ$^{-1}$. However, ethanol producers with natural gas-fired plants—that is, the most frequently deployed configuration—can reduce their emissions much further by installing a biomass gasification system, dropping the ethanol GWI from 65 to 45 CO$_2$e MJ$^{-1}$ for non-CHP configurations, or from 61 to 36 g CO$_2$e MJ$^{-1}$ for CHP configurations.

Although the cost advantage of retrofitting a biomass gasification system provides an incentive to switch to this technology, challenges relating to biomass logistics may delay widespread adoption of this option. The additional financial incentives generated by climate regulations may help overcome these hurdles.

A non-CHP coal-fired ethanol plant in Iowa can reduce the GWI of its ethanol from 101 to 89 g CO$_2$e MJ$^{-1}$ by co-firing 20% biomass in its boiler system, incurring only a small change in production costs in large part due to the right complement of equipment to accommodate biomass. Assuming delivered corn stover costs $55 Mg$^{-1}$ ($50$ ton$^{-1}$), this retrofit would reduce the cost of production by about $2.60$ kl$^{-1}$ ($0.01$ gal$^{-1}$); if delivered stover costs $83$ Mg$^{-1}$ ($75$ ton$^{-1}$), production costs would increase by about $5.20$ kl$^{-1}$ ($0.02$ gal$^{-1}$) [24].

Coal-fired ethanol facilities can also reduce their ethanol GWI, but the GWI remains above the assumed LCFS target except when employing multiple advanced process improvements (e.g., raw starch hydrolysis and corn oil extraction, plus either CHP or biomass co-firing), and even so the GWI is only a few g MJ$^{-1}$ below the 10% reduction target discussed in California [11].

Figure 1 highlights the importance of considering life cycle emissions: for natural gas and coal-fired dry mills, upstream emissions (everything but the ‘Plant fuel’ segment) constitute about 35% to 65% of the total life cycle emissions, whereas the vast majority of emissions associated with biomass configurations occur upstream of the plant.

Figure 2 shows ethanol production costs per gasoline liter equivalent for seven plant types under four policy options: no CO$_2$ policy, a policy measuring only direct plant CO$_2$ emissions, a policy measuring emissions on a life cycle basis, and for a low carbon fuel standard with a target of 79 g CO$_2$e MJ$^{-1}$. The default GREET LUC adder of 1 g CO$_2$e MJ$^{-1}$ is assumed. The biomass plants emit no direct CO$_2$ so there is no difference in costs for this plant type under the ‘no policy’ and ‘direct CO$_2$-only policy’ options. Biomass plants are only slightly more expensive than coal-fired plants at the assumed biomass cost ($855$ Mg$^{-1}$), and cheaper than natural gas-fired plants, but biomass-fired plants have much lower GHG emissions than either fossil fuel fired plant.

A CO$_2$ charge on life cycle emissions increases production costs by between $0.005$ and $0.008$ l$^{-1}$ per $10$/Mg CO$_2$ price increment, across all modeled plant energy systems, with increases under direct emissions somewhat lower in all cases. The difference in costs incurred under these two policies is small relative to total production costs. For example, at $50$/Mg CO$_2$, the difference in total production costs between these two policies ranges from $0.03$ to $0.04$ l$^{-1}$ ($0.10$ to $0.15$ gal$^{-1}$) across all plant types.

For the LCFS case, we assume a GWI target of 79 g CO$_2$e MJ$^{-1}$, representing a 10% reduction from the baseline GWI (88 g MJ$^{-1}$) as estimated for the California LCFS [11]. A price of $550$ Mg$^{-1}$ CO$_2$ translates to $1.10$/per gram CO$_2$e MJ$^{-1}$ per kL ethanol ($0.004$ g l$^{-1}$ CO$_2$e MJ$^{-1}$). For ethanol with a GWI above the target, this becomes an extra cost since the ethanol producer or purchaser may have to purchase offsets to sell this higher GWI ethanol into LCFS markets. Ethanol with a GWI rating below the target will command a premium. Figure 2 illustrates that under the stated assumptions, an LCFS increases the cost of production for coal-fired ethanol plants only; for all other plants the LCFS operates as a subsidy. In contrast, both CO$_2$ charge policies increase the cost of production across all plant types.

With the default GREET value of 1 g CO$_2$e MJ$^{-1}$ for emissions from land use change, carbon prices of $59$, $52$, and $59$ Mg$^{-1}$ are required to push the production costs of ethanol from coal-fired dry mills in Iowa above those of natural gas-fired facilities, under life cycle emissions, direct emissions, and LCFS policies (with a target of 79 g CO$_2$e MJ$^{-1}$), respectively. As of this writing, CO$_2$ was trading at $37$ ton$^{-1}$ in the European Trading System, a level likely to be insufficient to change investment decisions for ethanol plant investors.

While the three modeled policy options may not change investment decisions for ethanol plant investors, they do alter the cost relationship to gasoline. Figure 3 compares the incremental cost of different ethanol plant types to gasoline for the three policy options, assuming again a low carbon fuel standard with a target of 79 g CO$_2$e MJ$^{-1}$, a CO$_2$ cost of $550$ Mg$^{-1}$, and the default GREET value for land use change of 1 g CO$_2$e MJ$^{-1}$ of ethanol. Since gasoline is also assessed a charge under all three policy options, the impact of an increase in the cost of biofuels production is mitigated particularly for the lower GWI ethanol plant types, though the size of the mitigation will vary with the degree to which the charge to gasoline is reflected in the retail price at the pump [4].

9 Assuming the default GREET LUC adder of 1 g CO$_2$e MJ$^{-1}$.

10 BEACCON includes data on fuel costs and grid emissions factors for several states, however, we provide results here only for Iowa, which produces more ethanol than any other US state (Renewable Fuels Association, 2007).

11 On 3 April 2008, the price of an ETS EUA (European Union emission Allowance) was 23 EUD = 37 USD, as reported on www.pointcarbon.com.
4. Discussion

4.1. Accounting for land use change

On December 19, 2007, President Bush signed into law the Energy Independence and Security Act of 2007, which includes performance requirements for biofuels based on their life cycle greenhouse gas emissions. Importantly, the bill defines the boundaries of the life cycle accounting to include ‘direct emissions and significant indirect emissions such as significant emissions from land use changes’ [2].

Recent studies assert that land use change (LUC) caused or induced by the expansion of biofuels production can result in a significant loss of carbon from soil and above-ground biomass, potentially overwhelming the climate benefits of displacing petroleum fuels for decades [28, 29]. Searchinger et al estimate the carbon losses from LUC induced by increasing corn ethanol production in the US from 15 to 30 billion gal by 2015, using economic equilibrium modeling and a series of assumptions about affected ecosystems and carbon loss factors. If the estimated initial carbon loss is amortized over thirty years, it yields a land use adder for corn ethanol of 104 g CO2e MJ−1, which would more than double the GWI of average corn ethanol. However, there is no agreement yet on the appropriate methodology for estimating these effects, and the results can differ widely based on methodological decisions such as the treatment of time and assumptions regarding a range of agronomic and economic parameters.

4.2. Effect of land use change on ethanol production costs

Estimating an appropriate value for a LUC ‘adder’ is beyond the scope of this study. Rather, BEACCON includes an exogenous parameter for a land use change adder, allowing us to examine the effect this value would have on different policies. The default LUC adder used in BEACCON is taken from GREET 1.7, although that value (0.9 CO2e MJ−1) is recognized to be outdated and likely too low [37, 41].

Since all the ethanol plants in BEACCON are corn-based and are assumed to have the same conversion efficiency, under both CO2 charge policies a land use adder shifts the costs of all plants by a constant amount leaving the differences in GWI introduced by other variables (plant fuel, electricity, etc) unchanged. Under an LCFS, the effect of the LUC adder depends on its magnitude: as the adder pushes the GWI of a production system above the LCFS target, the CO2 price flips from a subsidy to a tax. If the LUC adder reaches 47 g CO2e MJ−1, none of the corn ethanol modeled would have a GWI lower than the assumed LCFS baseline of 79 g CO2e MJ−1. We note that this LUC adder is less than half of that estimated by Searchinger et al [29].

Figure 4 shows the additional cost of production due to an effective CO2 price of $50 Mg−1 and a land use change adder of 47 g CO2e MJ−1. With this adder, the lowest GWI pathway (Biomass CHP) achieves a GWI equal to the LCFS target of 79 g CO2e MJ−1, so the LCFS no longer subsidizes any of the fuels examined.

Even with a $50/Mg CO2 charge and a 47 g CO2/MJ land use adder, the estimated production costs of all seven ethanol plants under the direct CO2 and LCFS policies remain below $0.135 l−1 ($0.51 gal−1) if the $0.135 l−1 ($0.51 gal−1) federal excise tax credit accrues to the producer. With gasoline prices at $0.90 l−1 ($3.40 gal−1) it’s unlikely, even with a sizeable land use adder, that a direct CO2 policy would induce much innovation in the
corn ethanol sector. Increasing the land use adder under a life cycle CO₂ charge does not alter the differential between plant types since the land use adder is independent of plant energy system. However, if the adder were sufficient to push the GWI of ethanol above that of gasoline, ethanol would offer no advantage to regulated entities in LCFS markets. A more moderate adder could result in ethanol from lower GWI facilities (e.g. biomass-fired) rating below the regulatory target, and with ethanol from higher GWI facilities (e.g. coal-fired) rating above the standard or even above the rating for gasoline.

Increases in commodity and energy prices in early 2008, most notably the sharp rise in the price of corn to $6 bu⁻¹, have increased the cost of ethanol production by about $0.12 l⁻¹ ($0.45 gal⁻¹), eroding profit margins for ethanol producers across all plant types. Under these market conditions, any climate policy is likely to force some high cost or high GWI producers to exit the market.

5. Conclusions

We present a model of seven corn ethanol dry-mill configurations that integrates the accounting of the life cycle GHG emissions and production costs of ethanol production via apriCoe CO₂. We compare the effects on production costs of three policy alternatives: a CO₂ charge on direct plant GHG emissions only, a CO₂ charge on life cycle GHG emissions, and a low carbon fuel standard (LCFS).

The cost differential between policies regulating direct versus life cycle emissions remains small until the CO₂ price approaches $55 Mg⁻¹, at which point the cost differential between policies approaches 10% of non-CO₂ production costs for certain plant types.

Assuming a very small adder for land use change, an LCFS with a target of 79 g CO₂eMJ⁻¹ increases the cost of production for coal-fired ethanol plants only; for all other plants the LCFS operates as a subsidy. In contrast, both CO₂ tax policies modeled increase the cost of production across all plant types. A CO₂ tax or emissions reduction credit price of at least $50/Mg CO₂ is required to push the production costs of ethanol from coal-fired dry mills in Iowa above those of natural gas-fired facilities, under any of the modeled policies.

Several retrofit options are available to dry-mill plant operators to reduce the global warming intensity of their product. The greatest reduction available for the dominant natural gas-fired facilities is the use of biomass gasification to substitute producer gas for natural gas. Such retrofits can reduce ethanol GWI by 20–25 g CO₂eMJ⁻¹, depending on the base configuration.

Coal-fired ethanol facilities can also reduce their ethanol GWI, but the GWI remains above the assumed LCFS target except when employing multiple advanced process improvements (e.g. raw starch hydrolysis and corn oil extraction, plus either CHP or biomass co-firing), and even so, the resulting GWI is only slightly below the target.

A land use change adder of 63 g CO₂eMJ⁻¹ pushes the GWI of ethanol from all the modeled systems beyond that of gasoline; with a 47 g MJ⁻¹ adder, all of the ethanol modeled would have a higher GWI than the assumed LCFS target. However, all the modeled systems would be viable under a CO₂ tax—just more expensive, and perhaps still cheaper than gasoline. The precise outcome depends on several factors, including the relationship between the cost of ethanol production and the price of gasoline, the size of the land use change adder, and the cost of emission reduction credits.
The viability of crop-based biofuels as a climate change mitigation strategy depends strongly on the magnitude of the land use change adder. More research and methodological development is urgently required in this area to guide commercial development and public policy.

Acknowledgments

The authors thank Stefan Unnasch and Brent Riffel for their contributions to the BEACCON model, and Alex Farrell and two anonymous reviewers for their helpful comments. This material is based upon work supported under a National Science Foundation Graduate Research Fellowship (Plevin).

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